EASiTool

V2.0

User Manual

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Introduction

Welcome to the second released version of EASiTool (Enhanced Analytical Simulation Tool), developed for CO_2 storage-capacity estimation and uncertainty quantification.

This User Manual will help you install and use EASiTool.

EASiTool is intended to help users achieve a fast, reliable, science-based estimate of storage capacity for any geological formation containing brine. EASiTool, which provides strategies for optimizing a project's net present value (NPV), offers three major features:

- An advanced, closed-form analytical solution for pressure-buildup calculations used to estimate both injectivity and reservoir-scale pressure elevation, in both closed- and open-boundary aquifers (version 1.1)
- A simple geomechanical model coupled with a base model to evaluate and avoid the possibility of fracturing reservoir rocks by injecting cold, supercritical CO_2 into hot formations, which can cause rock deformation (version 2.0)
- An active reservoir-management system throughout the brine-extraction process (version 3.0, to be released in 2016)

Disclaimer

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Further Information

This software has been developed using MATLAB R2015a.

What's New?

Important changes in EASiTool V2.0:

- The program platform has been transferred from GoldSim to MATLAB.
- A simple geomechanical model has been coupled with the base model to evaluate the maximum injection pressure internally. User still has the option to enter the maximum injection pressure manually.
- Graphical outputs have been added to the results. Outputs include capacity vs. number of injection wells, NPV vs. number of injection wells, extend of CO_2 plume in injection area, optimal injection rate of wells, and tornado chart for sensitivity analysis.

Getting Started

This section has information on system requirements and installment for EASiTool.

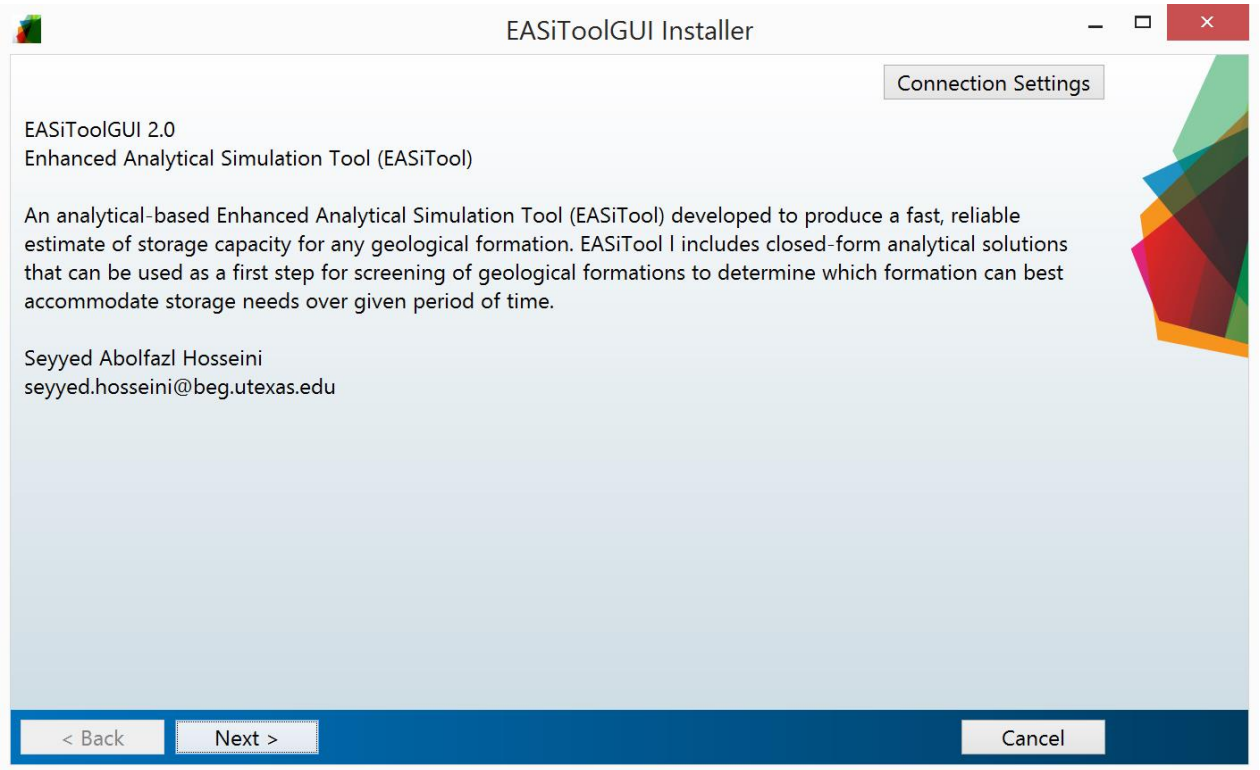
System Requirements

EASiTool is a Windows application. Windows Vista, Windows 7 (either 32-bit or 64-bit versions), or Windows 8 are the recommended operating systems. Windows XP (SP3) is also supported.

You must have administrative privileges on the system. You need a minimum of 600 MB disk space during the installation process. 16-bit color depth is required (32-bit recommended).

Installment

Once you download the install file from EASiTool website, double-click it to start the installment. Click "Next" once you see the window below:


EASiToolGUI Installer
Connection Settings
EASiToolGUI 2.0
Enhanced Analytical Simulation Tool (EASiTool)
An analytical-based Enhanced Analytical Simulation Tool (EASiTool) developed to produce a fast, reliable estimate of storage capacity for any geological formation. EASiTool l includes closed-form analytical solutions that can be used as a first step for screening of geological formations to determine which formation can best accommodate storage needs over given period of time.
Seyyed Abolfazl Hosseini
seyyed.hosseini@beg.utexas.edu
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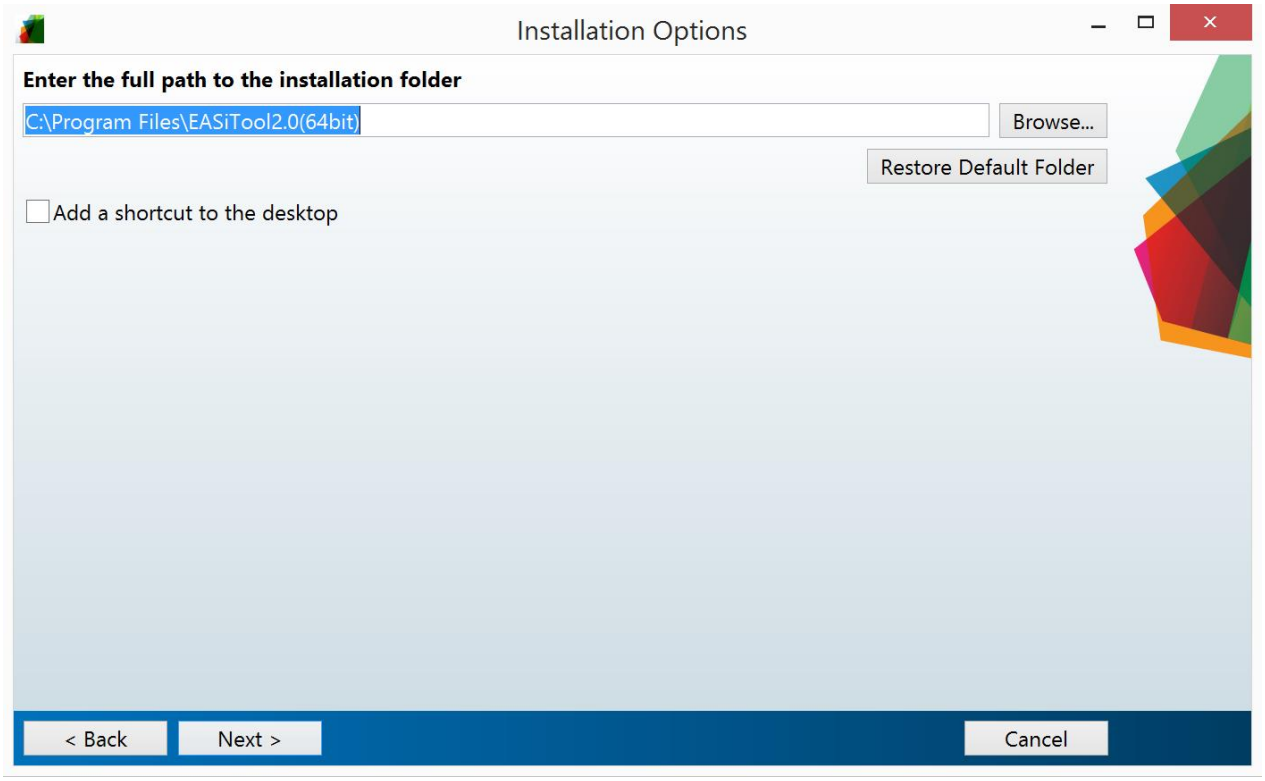
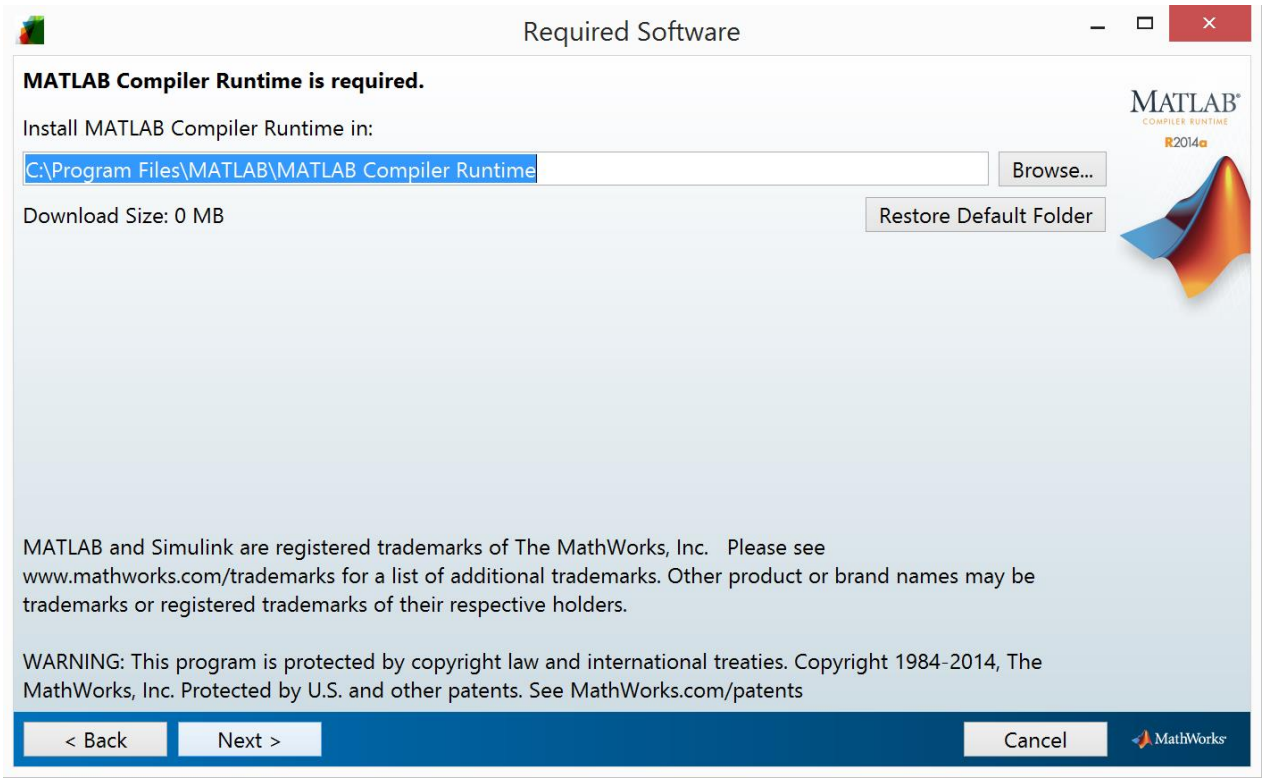
Determine the destination folder. If you don't want to change the location where the installation folder will be saved, click "Next":



MATLAB Compiler Runtime is required. Determine the destination folder. If you don't want to change the location where the installation folder will be saved, click "Next":


Required Software
MATLAB Compiler Runtime is required.
Install MATLAB Compiler Runtime in:
C:\Program Files\MATLAB\MATLAB Compiler Runtime
Browse...
Download Size: 0 MB
Restore Default Folder
MATLAB
R2014a
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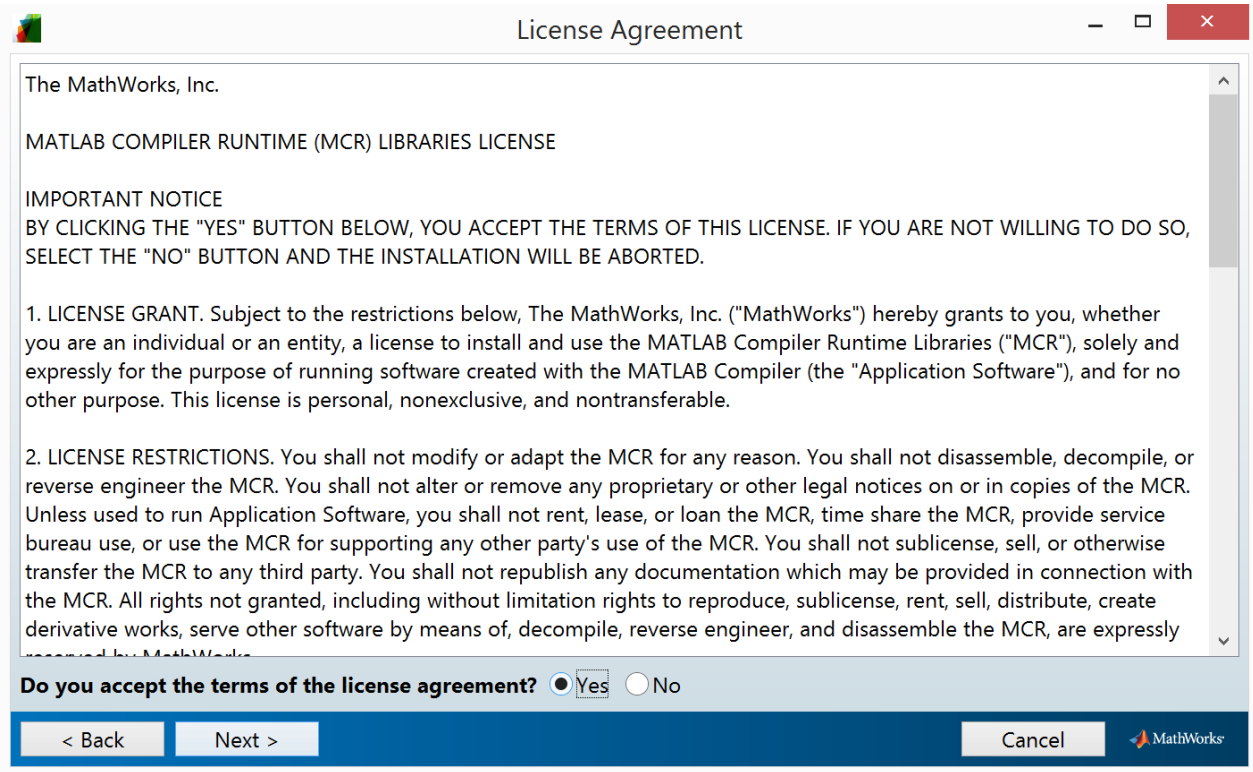
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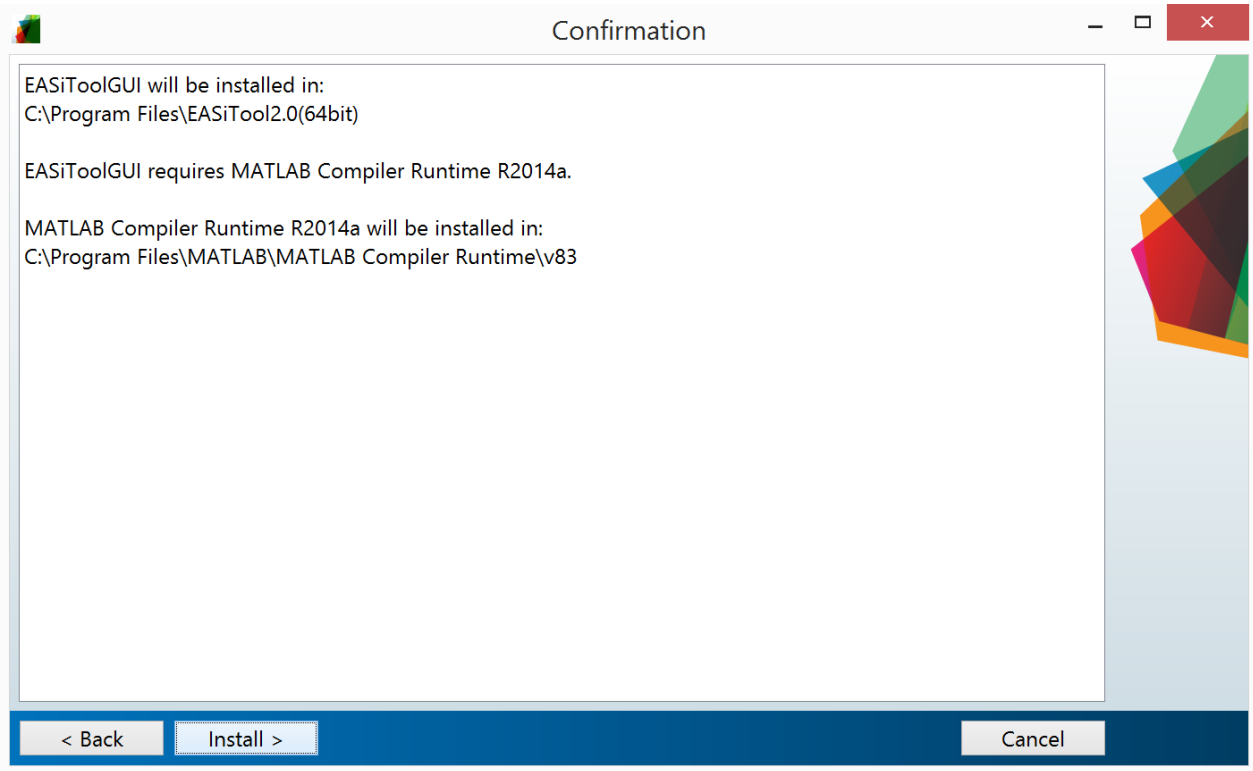
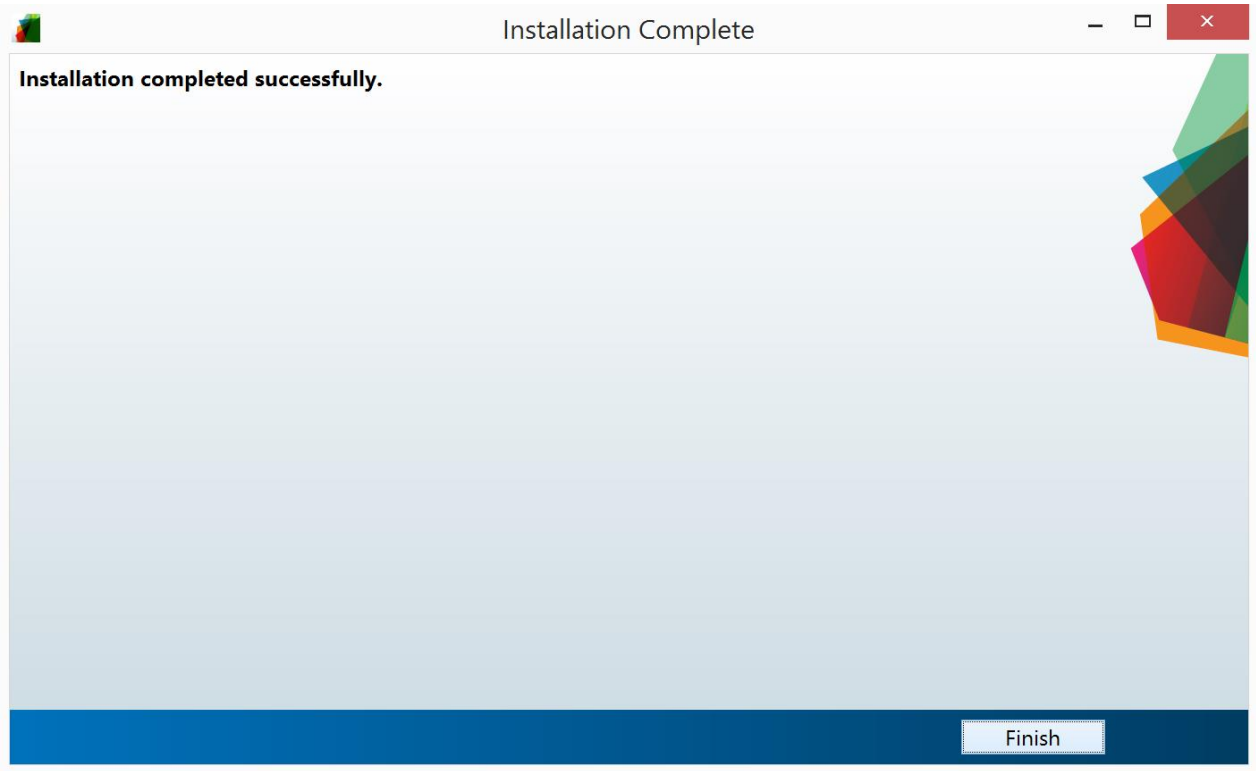
Click "Install" to begin the installation:



Once the installation is completed (this may take a few minutes), you will see the window below. Click "Finish":



Now you are ready to use EASiTool software by simply double-clicking on the EASiTool icon.

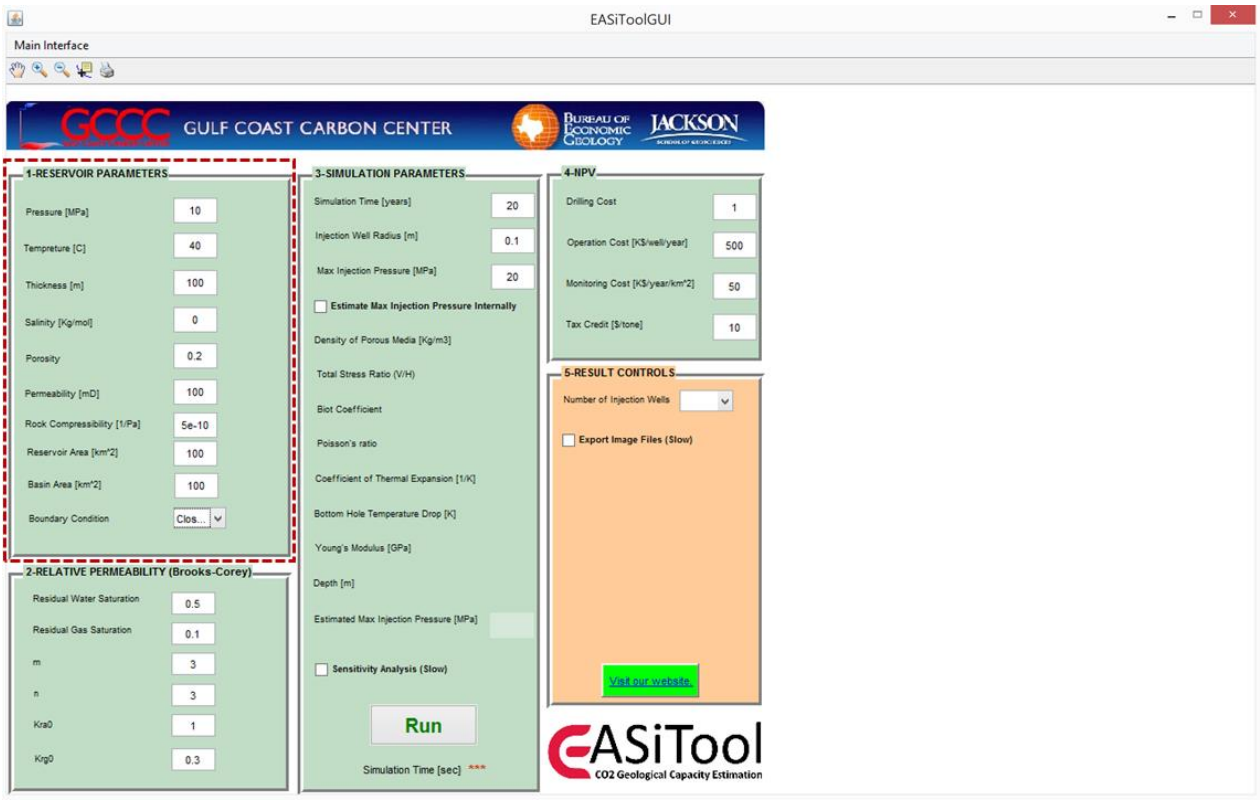
Input Parameters

Section 1 has information on the input data required to run the program.

1. Reservoir Parameters

Necessary input for reservoir parameters includes in situ pressure (MPa), temperature (C), salinity of the formation brine (mol/kg), thickness (m), porosity, permeability (mD), rock compressibility (1/Pa), reservoir area (km^2), basin area (km^2), and boundary condition, as shown in Section 1 at the top left-hand side of the input screen.

> **Note**: Currently we only accept one set of fixed units; if units are different from what is shown on the interface, they have to be converted first.

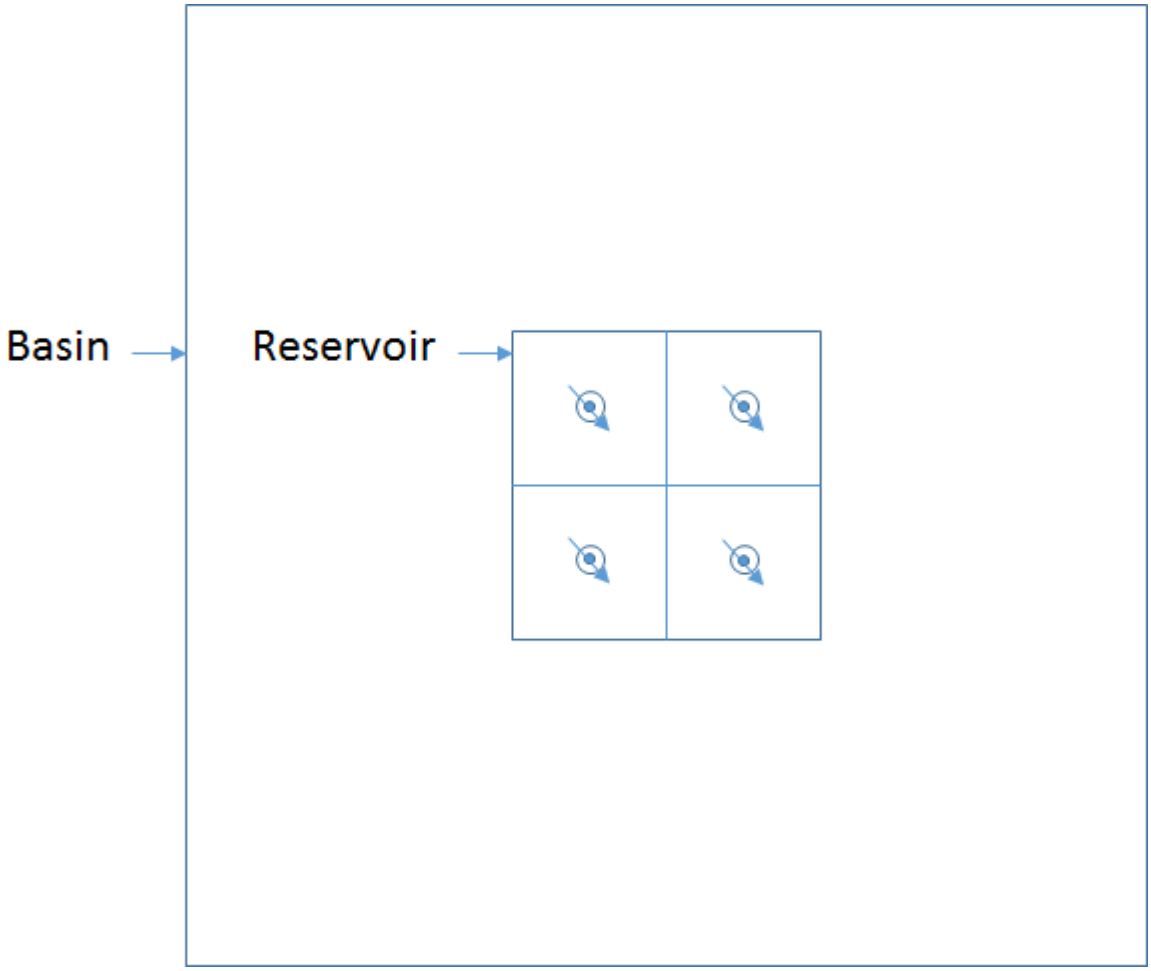


Reservoir Area (km^2): A reservoir is a part of the basin in which injectors are distributed. In the current version, we assume that reservoirs do not include detailed structures or dip angles. We also assume that reservoirs are square and placed at the center of the basins.

Basin Area (km^2): A basin is the whole areal extent of the storage formation in which the reservoir of our interest is located. In the current version, we assume that basins do not include detailed structures or dip angles. We also assume that basins are square. Basin area should be bigger or equal to reservoir area.

Boundary Condition: Using the drop-down menu, select either an "open" or a "closed" boundary condition. (In the current version of EASiTool, the selected boundary condition will be enforced on all four sides of the basin.) A reservoir can be considered open as long as the pressure change has not reached the boundaries. In an industrial-scale injection operation, it is expected that the pressure effect reaches the boundaries of the basin at late times.

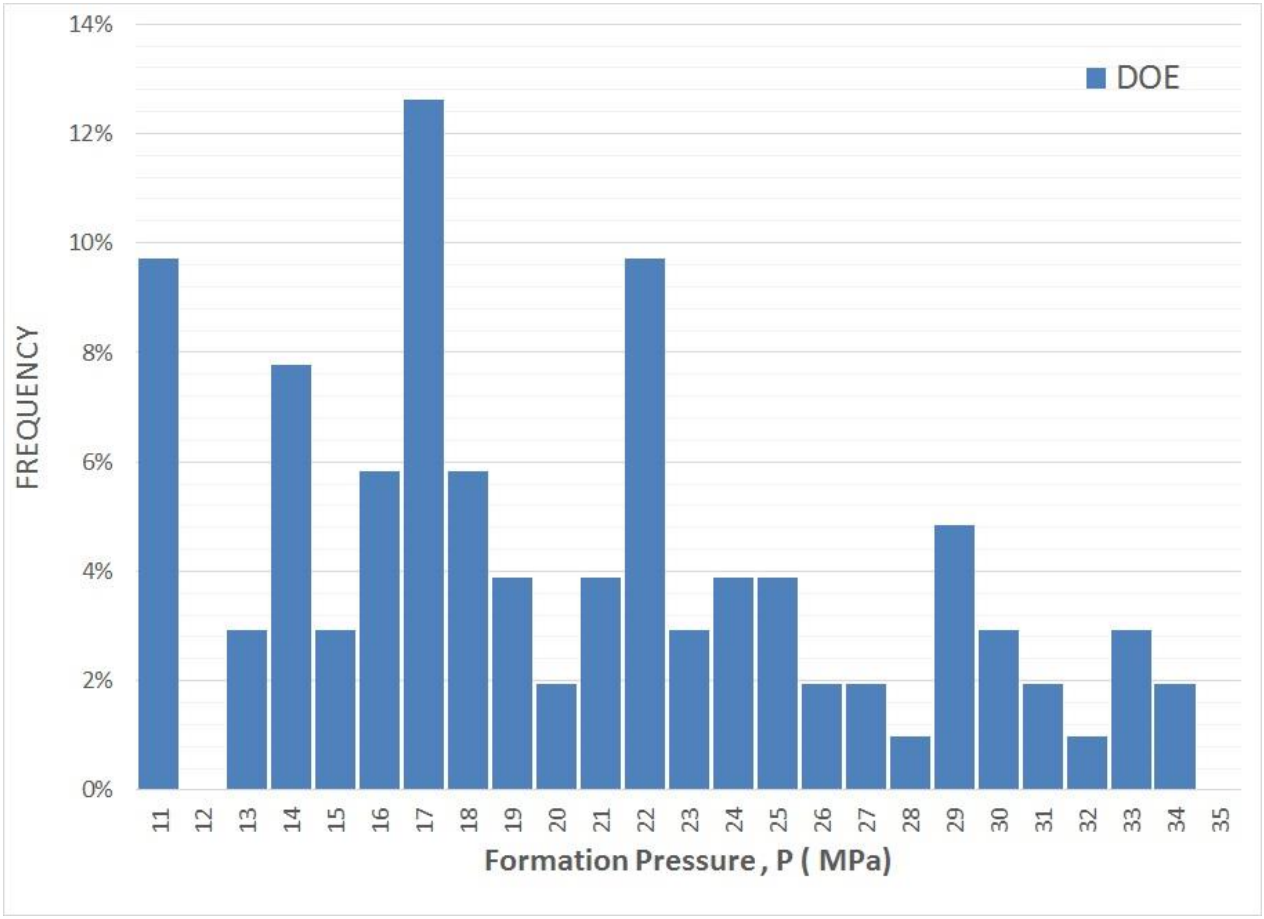
Note: EASiTool is designed to do the calculations for multiple scenarios where the number of wells increases from 1 to 400 in square numbers (1×1, 2×2, 3×3, 4×4, ..., 20×20). In each scenario, wells are equally spaced over the reservoir area. For example, well distribution for a 2×2 pattern is as shown below:



The following table shows the range of parameters that are accepted by EASiTool:

Initial Pressure	≤ 60.0 MPa
Initial Temperature	≤ 300.0 ˚C
Thickness	≥ 0.1 m
Salinity	≥ 0.0 mol/kg and ≤ 6.0 mol/kg
Porosity	≥ 0.0 and ≤ 0.9999
Permeability	≥ 0.0 mD
Rock Compressibility	≤ 1.0E-08 1/Pa
Reservoir Area	≤ Basin Area

The following six figures show the range and frequency of some reservoir parameters, based on two data sets prepared by DOE and USGS:


DOE
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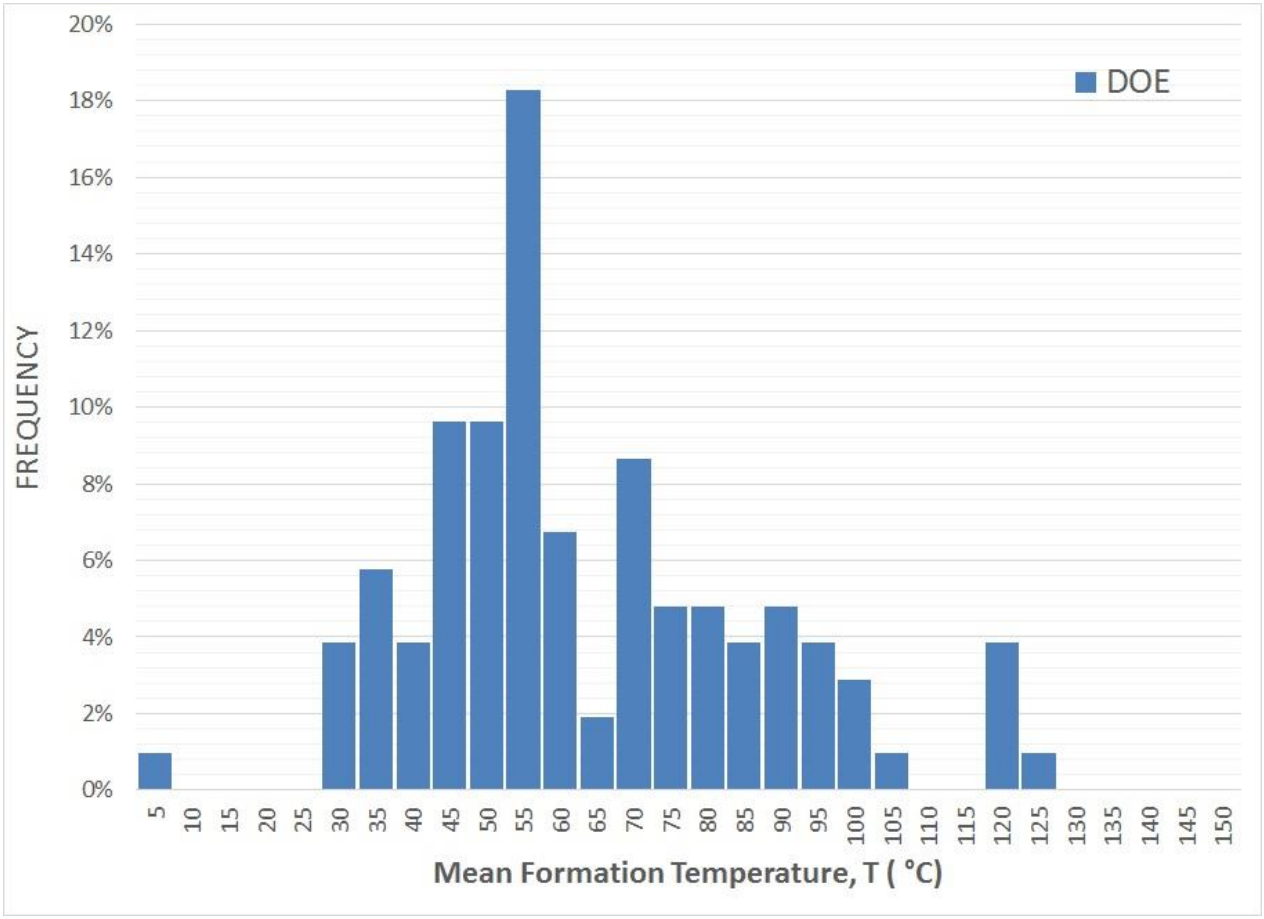
11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35
Formation Pressure , P (MPa)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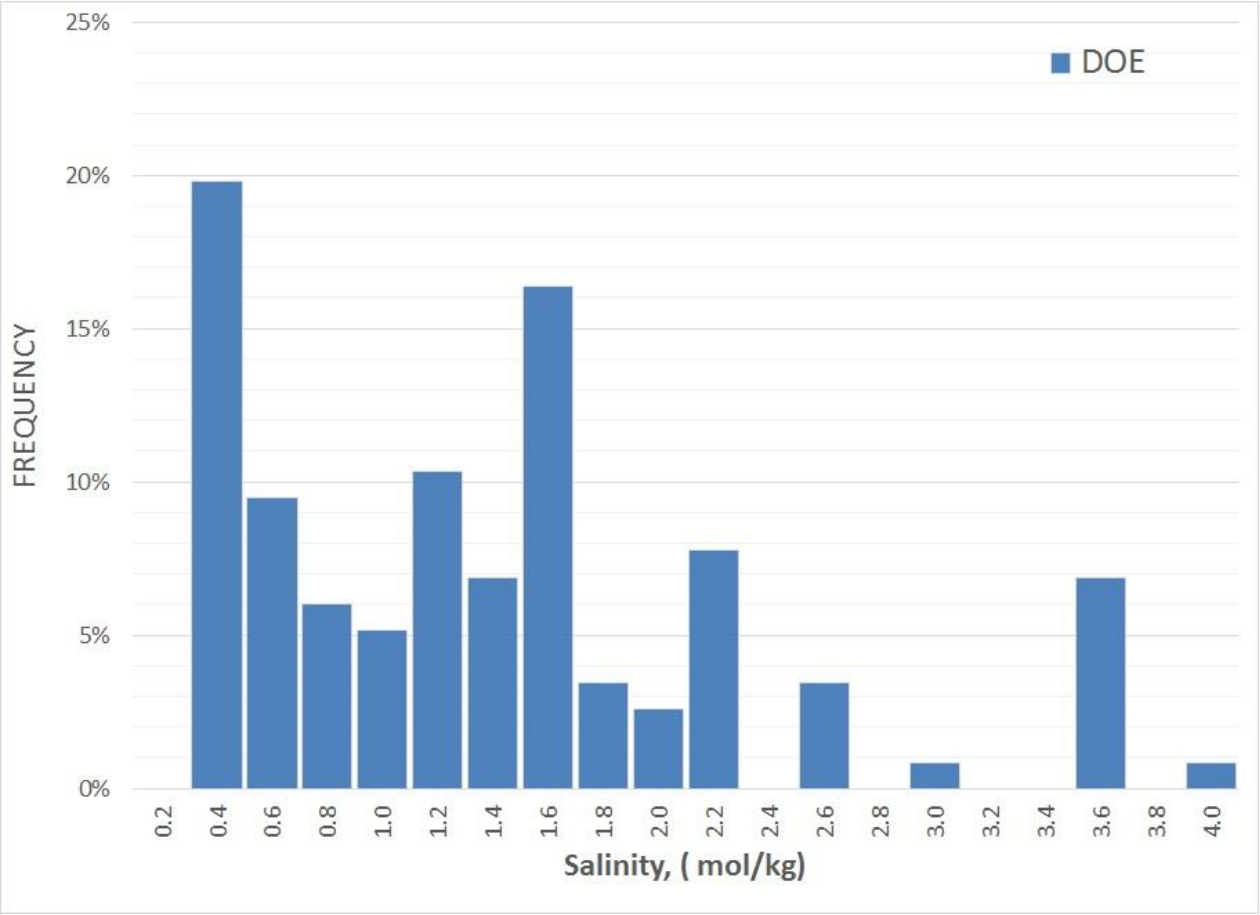
Mean Formation Temperature, T (°C)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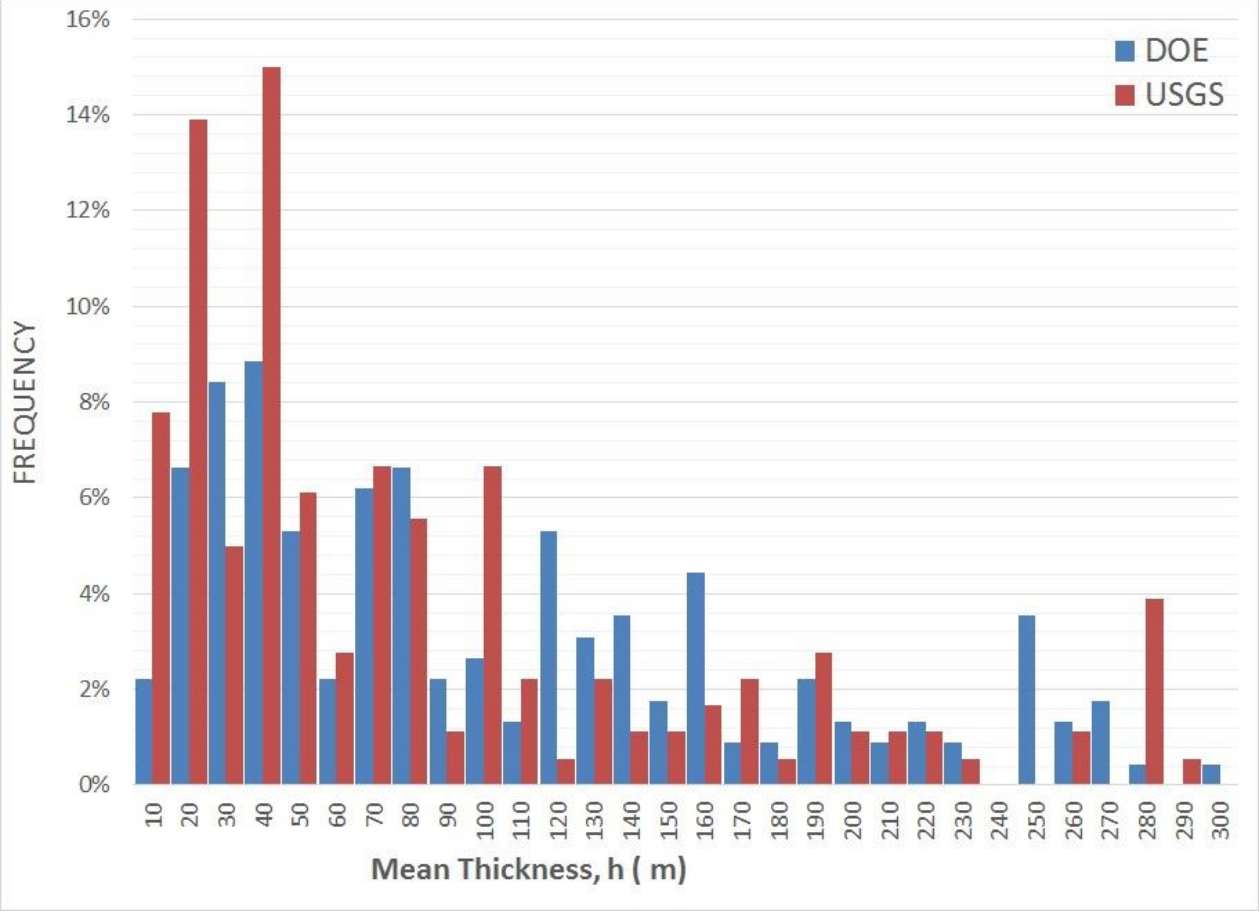
2.8
3.0
3.2
3.4
3.6
3.8
4.0
Salinity, (mol/kg)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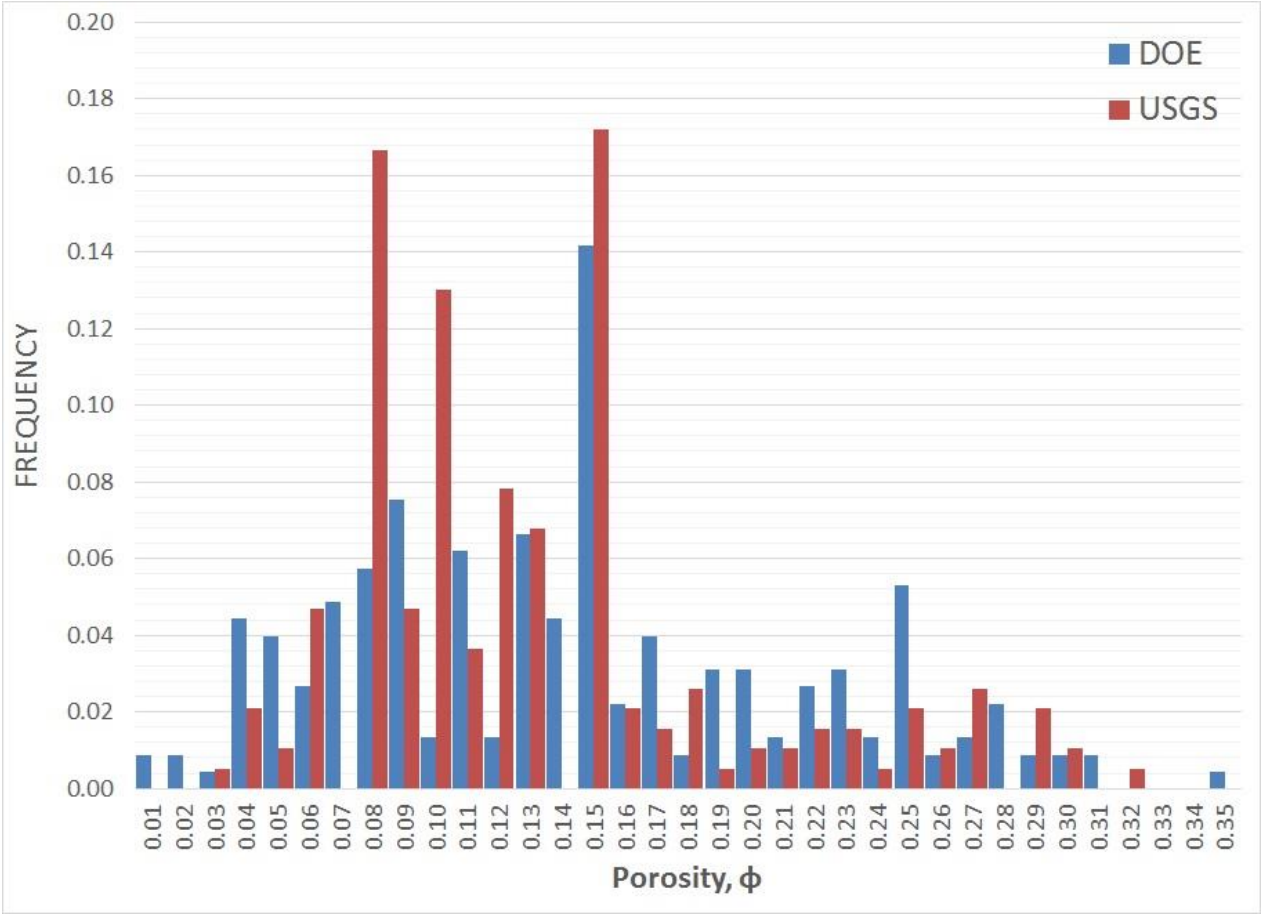
290
300
Mean Thickness, h (m)


DOE
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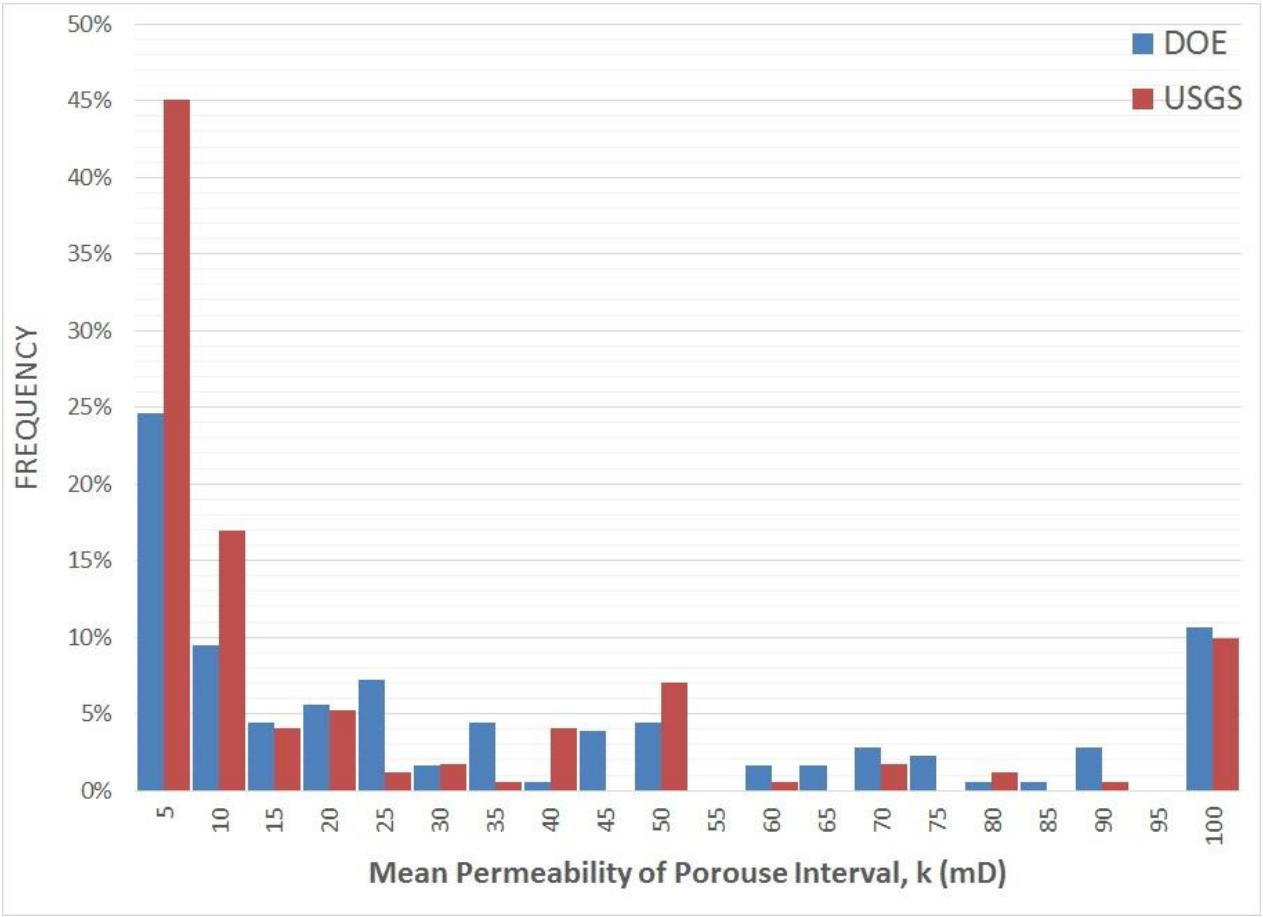
Porosity, ϕ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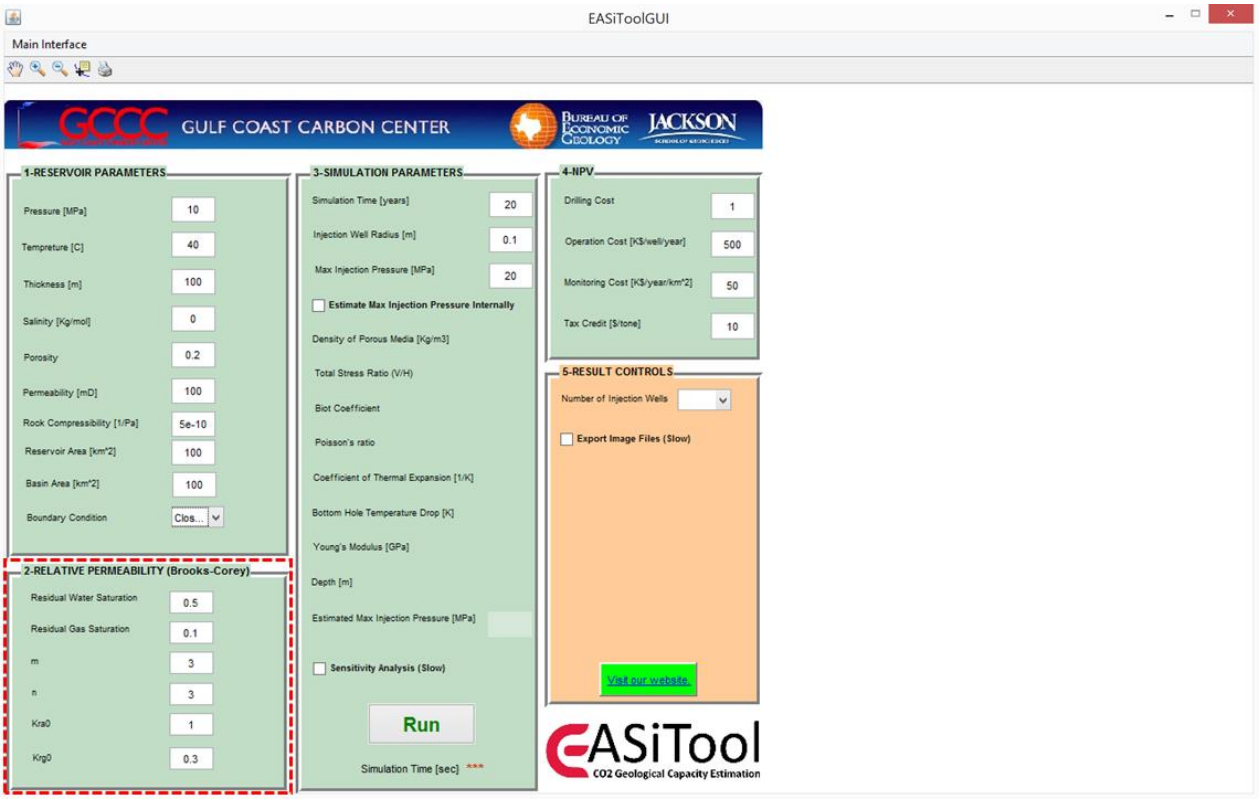
Mean Permeability of Porouse Interval, k (mD)

2. Relative Permeability Parameters

Section 2 allows input of parameters for relative permeability, including residual saturation of brine (S_{ar}), critical gas saturation (S_{gc}), end-point relative permeability for aqueous phase (k_{ra0}), end-point relative permeability for gas phase (k_{rg0}), and power-law exponents for the aqueous and gas phases *m* and *n*. This section includes equations for relative permeability calculations from the Brooks-Corey model:

$$k_{ra} = \begin{cases} 0, & S_a < S_{ar} \\ k_{ra}^{\circ}\left(\frac{S_a - S_{ar}}{1 - S_{ar} - S_{gc}}\right)^m, & S_a > S_{ar} \end{cases}$$

$$k_{rg} = \begin{cases} 0, & S_g < S_{gc} \\ k_{rg}^{\circ}\left(\frac{S_g - S_{gc}}{1 - S_{ar} - S_{gc}}\right)^n, & S_g > S_{gc} \end{cases}$$



The following table shows the range of relative permeability parameters that are accepted by EASiTool:

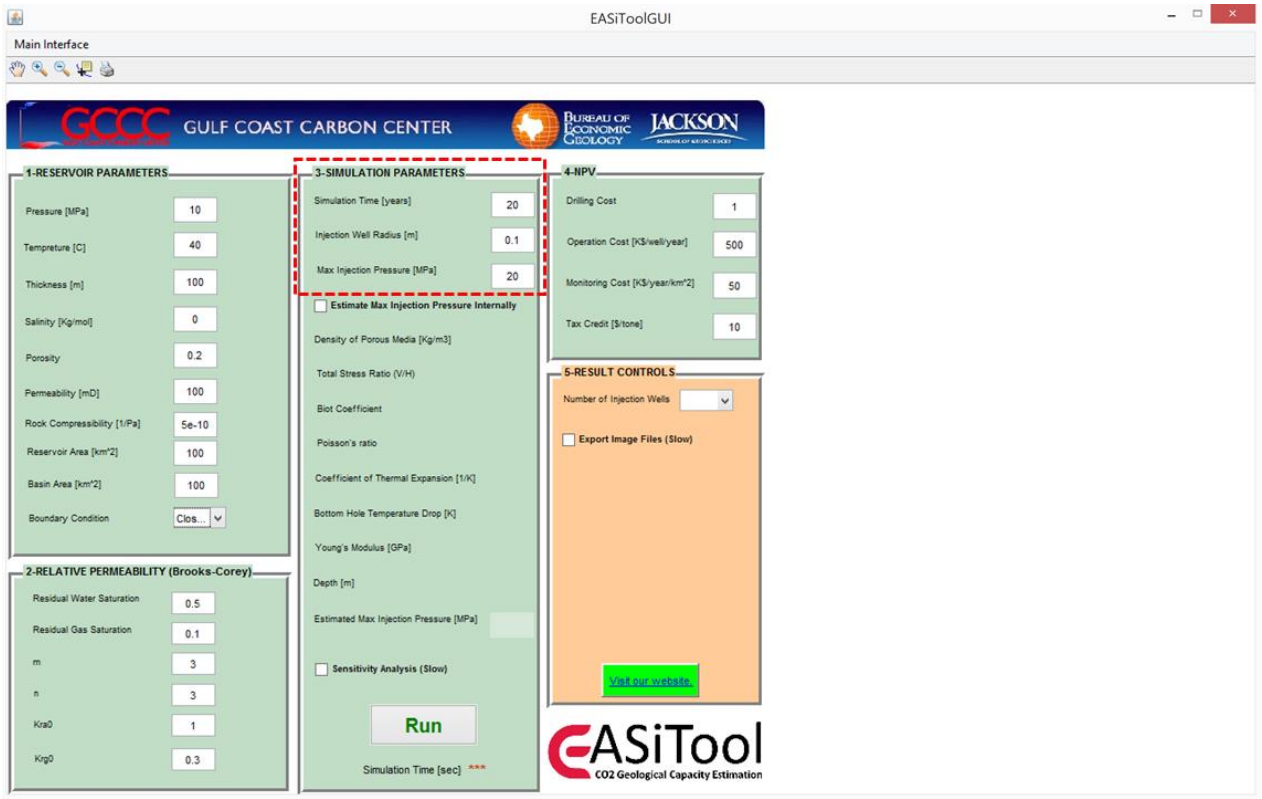
Residual water saturation, Sar	≥ 0.0 and ≤ 0.9999
Residual gas saturation, Sgr	≥ 0.0 and ≤ 0.9999
Water relative permeability Corey exponent, m	≤ 1.0
Gas relative permeability Corey exponent, n	≤ 1.0
Water end-point relative permeability, Kra0	≥ 0.0 and ≤ 1.0
Gas end-point relative permeability, Krg0	≥ 0.0 and ≤ 1.0

Typical range of relative permeability parameters based on data published in literature is listed in the table below:

Residual water saturation, Sar	0.2 – 0.6
Residual gas saturation, Sgr	0.1 – 0.35
Water relative permeability Corey exponent, m	1.5 – 4.0
Gas relative permeability Corey exponent, n	1.5 – 4.0
Water end-point relative permeability, Kra0	1.0
Gas end-point relative permeability, Krg0	0.1 – 0.6

3. Simulation Parameters

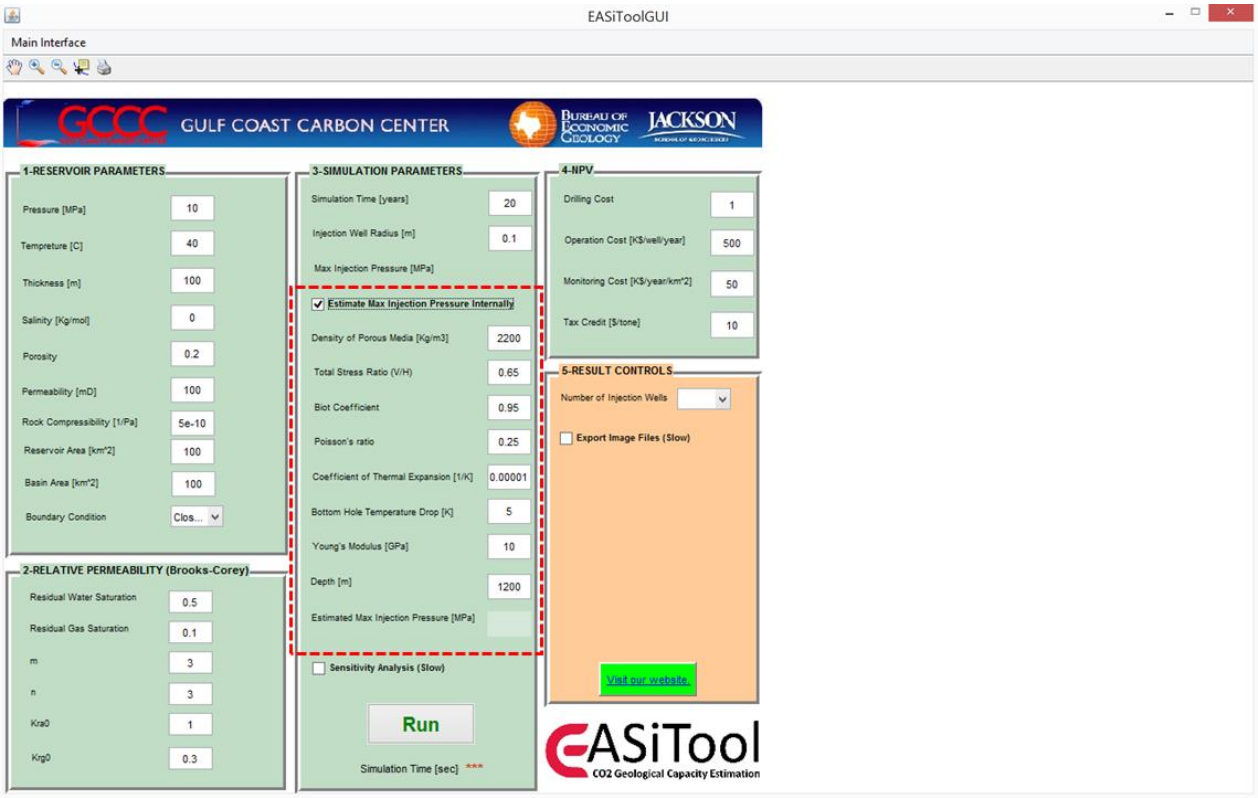
Section 3 has three input parameters for simulation: simulation time (years), injection well radius (m), and maximum injection pressure (MPa).



The maximum acceptable injection well radius is 1.0 m. The maximum injection pressure should also be larger than the initial pressure and smaller than three times the initial pressure.

Geomechanics Package

The new version of EASiTool can calculate the maximum allowable injection pressure internally from the reservoir properties. To include the geomechanics, check "Estimate Max Injection Pressure Internally". Then, in the new boxes, provide the following properties to estimate the maximum injection pressure:



Density of Porous Media (ρ) [kg/m^3]: Density of porous media can be calculated as $\rho=\rho_d (1-\varphi) + \varphi \rho_f$, where φ is porosity; ρ_f is fluid density; and ρ_d is dried density of the matrix.

Total Stress Ratio (V/H): The ratio of vertical to horizontal stress ($1/K_h$). K_h is coefficient of lateral stress or lateral stress ratio σ_h/σ_v.

Biot Coefficient (α): The effective-stress principle is of fundamental significance in soil and rock mechanics and is defined as $\sigma_{eff} = \sigma_c - \sigma_p$, where σ_c and σ_p are the total confining stress and fluid pore pressure, respectively. However, in fluid-saturated rocks, Terzaghi's effective-stress principle may not be always valid. The Biot coefficient α (other than unity) was suggested to modify the effective-stress principle (Biot, 1941), which is given by $\sigma_{eff} = \sigma_c - \alpha \sigma_p$. The Biot coefficient α is a property of a solid constituent only. The existence of the Biot coefficient suggests that pore pressure modifies not only effective normal stresses but also effective shear stresses.

Note: $\varphi \leq \alpha \leq 1$, where φ is porosity; α will be near its upper limit for soil-like materials.

Poisson's Ratio (ν): An elastic constant that is a measure of the compressibility of material perpendicular to applied stress, i.e., the ratio of latitudinal to longitudinal strain ($0<\nu<0.5$). Poisson's ratio can be expressed in terms of properties that can be measured in the field, including velocities of P-waves and S-waves. Approximate Poisson's ratio for carbonate rocks is ~ 0.3; for sandstones, ~ 0.2; and for shale, above 0.3.

Coefficient of Thermal Expansion [1/K]: The coefficient of thermal expansion describes how the size of an object changes with a change in temperature. Specifically, it measures the fractional change in size per degree change in temperature at a constant pressure.

Bottom-Hole Temperature Drop [1/K]: The temperature difference between the formation and the injected fluid (CO_2) at the bottom of the well bore. The fluid temperature is lower than the bottom-hole static temperature. The corresponding temperature difference causes thermal stresses in the formation and affects the Max Injection Pressure.

Young's Modulus (E) [Pa]: Young's modulus, also known as the tensile modulus, modulus of elasticity, or elastic modulus, is defined as the ratio of the stress (force per unit area) along an axis to the strain (ratio of deformation over initial length) along that axis in the range of linear behavior of the material.

Depth [m]: Depth of the fluid injection (depth of perforation zone).

Estimated Max Injection Pressure [MPa]: Pressure above which injection of fluids will cause the rock formation to fracture hydraulically. Reactivation of preexisting fracture planes via shear slip is likely to occur prior to other types of geomechanical failures in most cases. The Mohr-Coulomb shear failures criterion for the maximum pressure limit P_{max} is expressed as

$$\tau = c + (\sigma_n - \alpha P_{max})\mu,$$

where τ is shear stress, σ_n is normal stress acting on a preexisting fracture plane, c is cohesion, and μ is the coefficient of friction.

Then, the P_{max} is

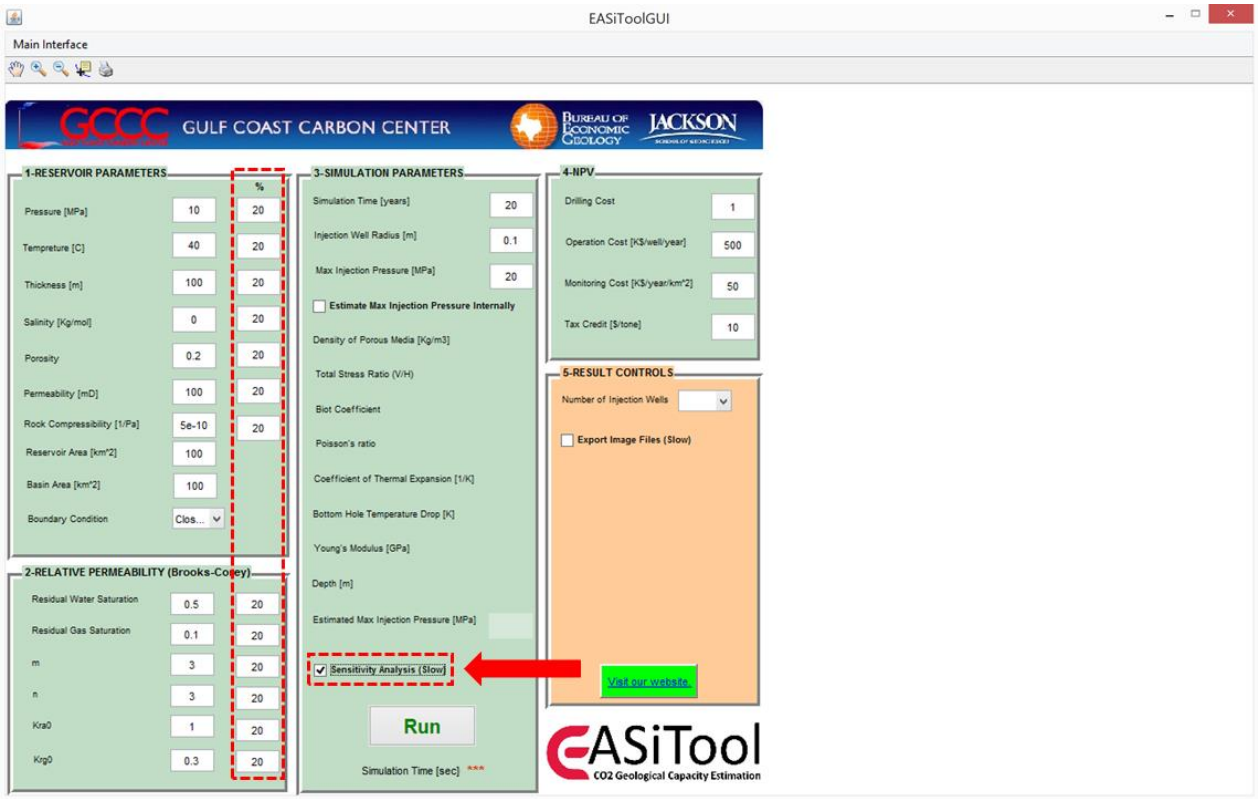
$$P_{max} = \frac{1}{\alpha}\left[\frac{1}{2}(\sigma_1 + \sigma_3) + \frac{1}{2}(\sigma_1 - \sigma_3)cos2\theta - \frac{1}{2}(\sigma_1 - \sigma_3)\frac{sin2\theta}{\mu}\right],$$

where σ_1, σ_3, and θ are major principal stress, minor principal stress, and angle with reference to minor principal stress, respectively.

Sensitivity Analysis

EASiTool currently can do sensitivity analysis on any combination of initial reservoir pressure, temperature, salinity, thickness, porosity, permeability, rock compressibility, and relative permeability parameters. To include the sensitivity analysis of any of these parameters, check "Sensitivity Analysis (Slow)". Then, in the new boxes, provide the percentage of the variation of the parameters for sampling.

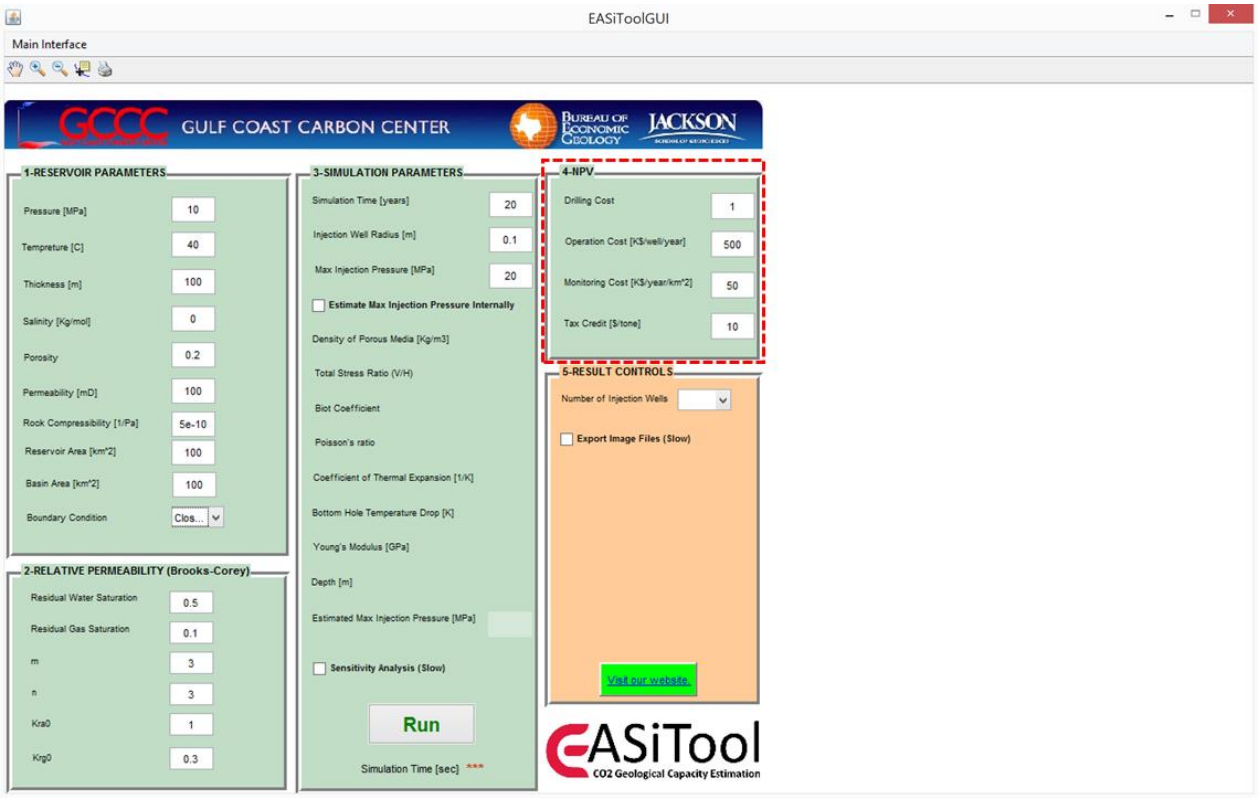
The one-parameter-at-a-time method is used for sampling in this version of EASiTool. In this method, information about the effect of a parameter is gained by varying only one parameter at a time. Because this procedure is repeated in turn for all parameters to be studied, running sensitivity analysis simulations may take a few minutes to complete.



Sensitivity-variation value should be less than 100% and greater than 0%.

4. NPV Analysis

Section 4 provides the option to conduct a very simple net present value (NPV) analysis along with the simulation. Here, you can input parameters such as Drilling Cost (million $/well), Operation Cost (kilo $/well/year), Monitoring Cost (kilo $/year/km^2), and Tax Credit ($/tonne):

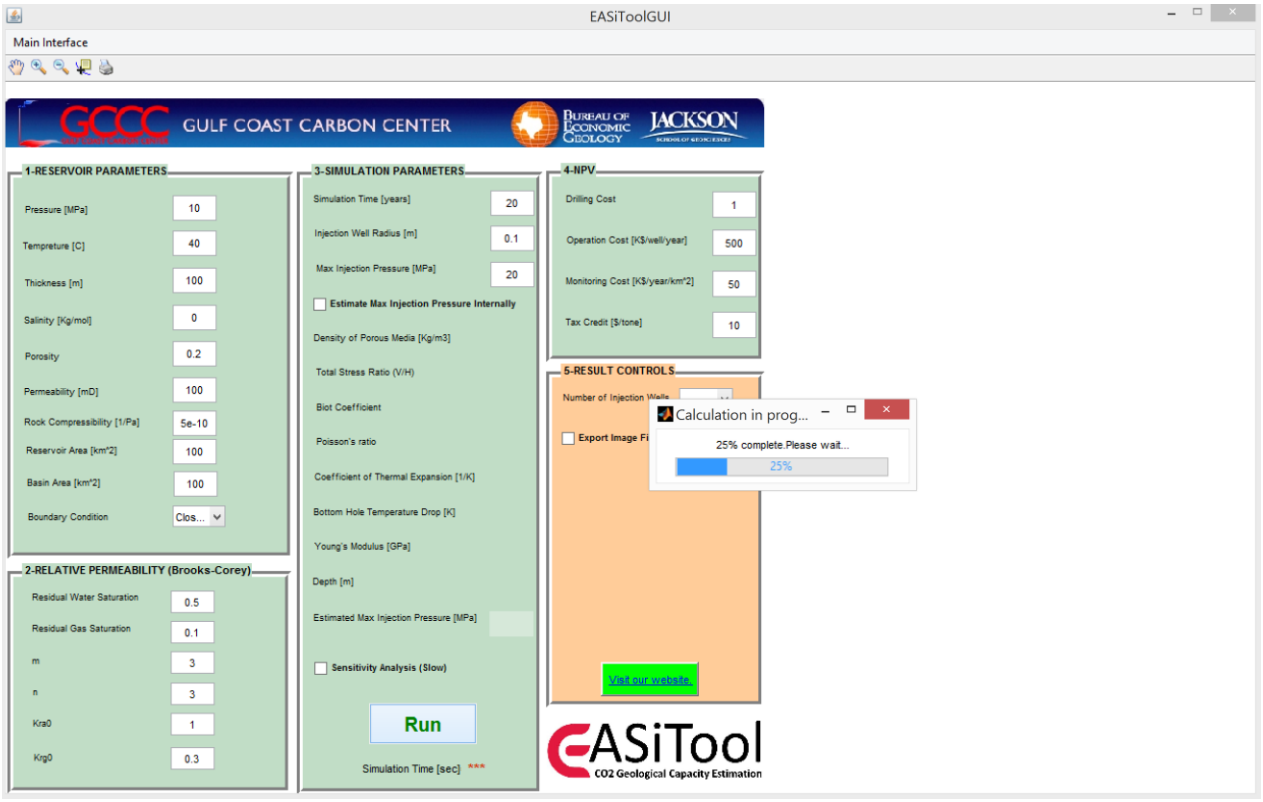


The following table shows the range of NPV parameters that are accepted by EASiTool:

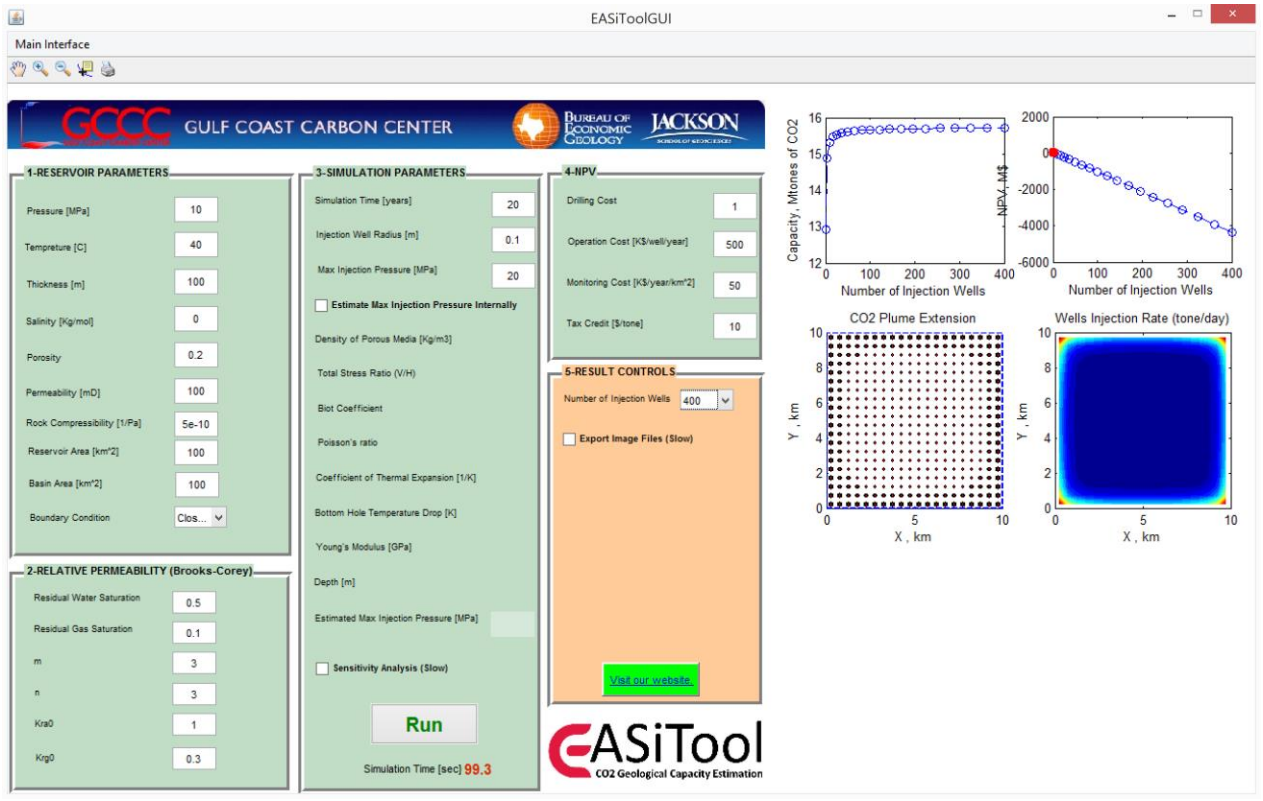
Drilling Cost	≥ 0.0001 million $/well
Operation Cost	≥ 0.0001 kilo $/well/year
Monitoring Cost	≥ 0.0001 kilo $/year/km^2
Tax Credit	≥ 0.0 $/tonne

Running the Simulation

To run the simulation, click "Run" in the EASiTool interface. A progress bar pops up, showing the percentage of the progress in calculations:



The simulation results will appear on the right side of the controller window to inform you that the simulation is complete:

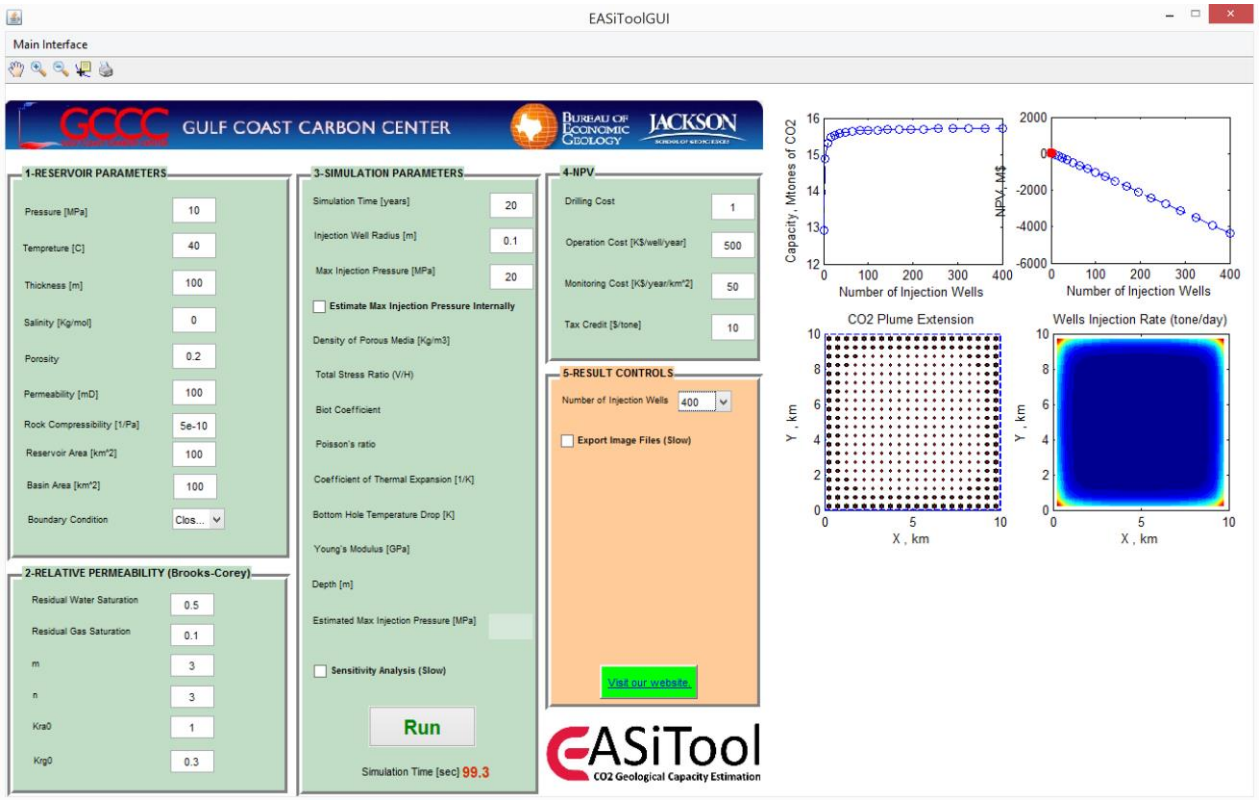


Outputs

This section provides information on how to evaluate the outputs of EASiTool.

1. Optimal Constant-Injection Rate

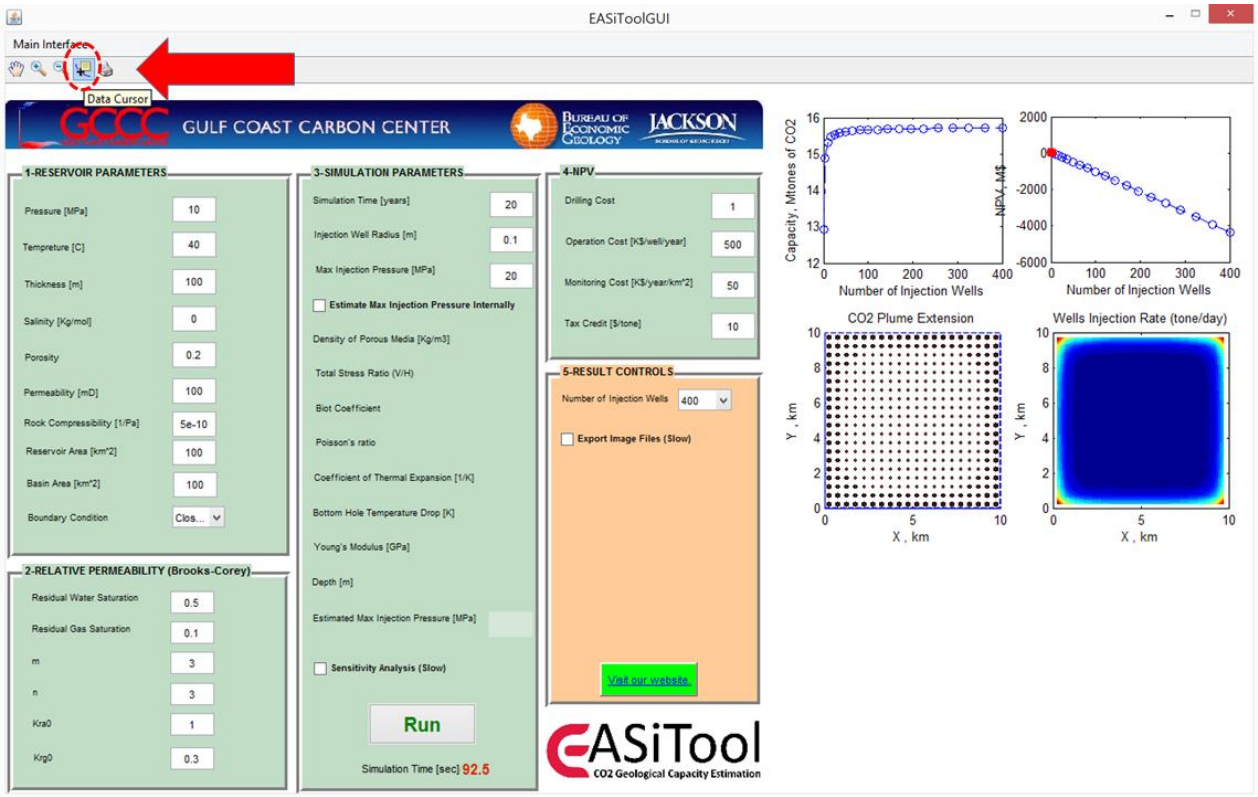
After completing a simulation, you can see the results on the right hand side of the window:



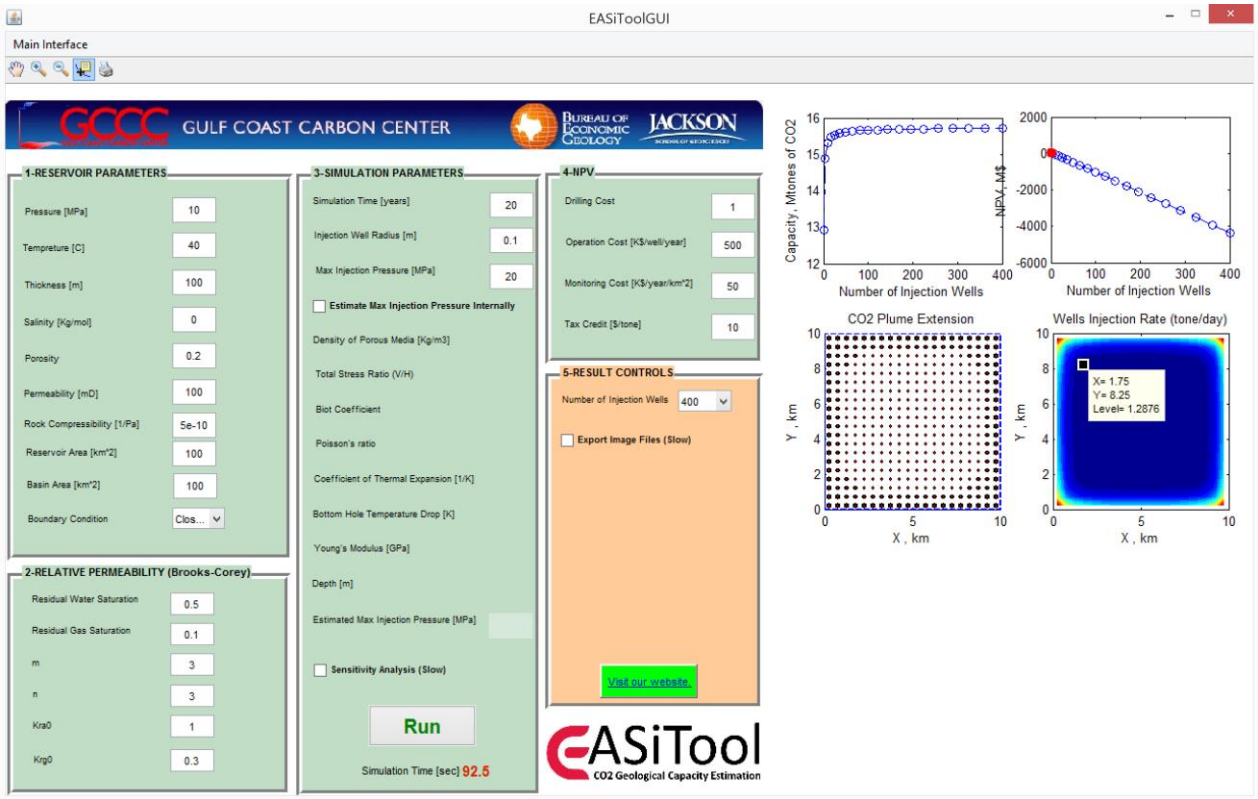
The results include the "Storage Capacity ($MtCO_2$)," "NPV ($M)," "$CO_2$ Plume Extension (Graphical map view)," and "Well Injection Rate (tonne/day)."

In the orange "Results Controls" box, check the "Export Image Files (Slow)" to save the graphical results at the location where the installation folder was installed.

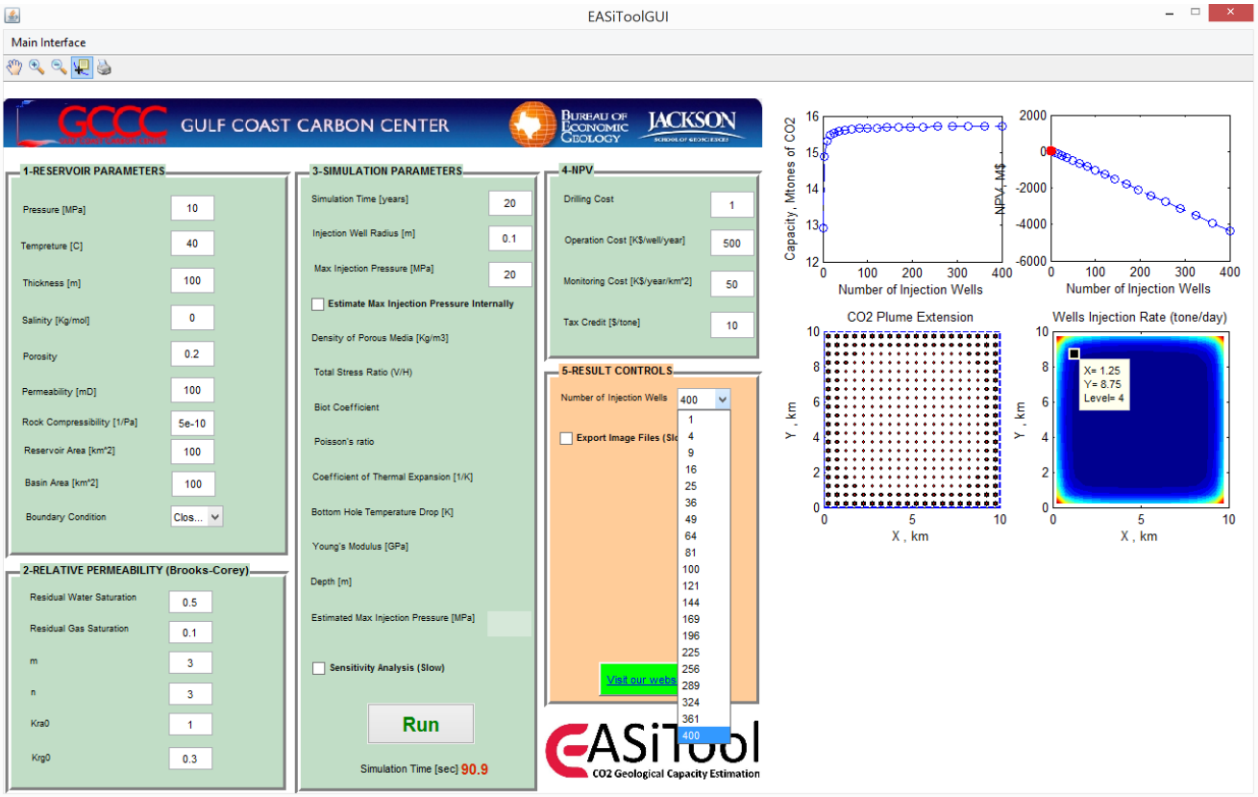
To look at the values, press the "Data Cursor" icon in the upper tab:



Then, click on the "Well Injection Rate" contour to see the value and coordinates of each well:



The number of injection wells can be changed by clicking on the drop-down menu for "Number of Injection Wells":



The total CO_2 storage capacity and NPV of the simulated scenario based on number of injection wells can be viewed by clicking on the circles of the "Capacity" and "NPV" plots.

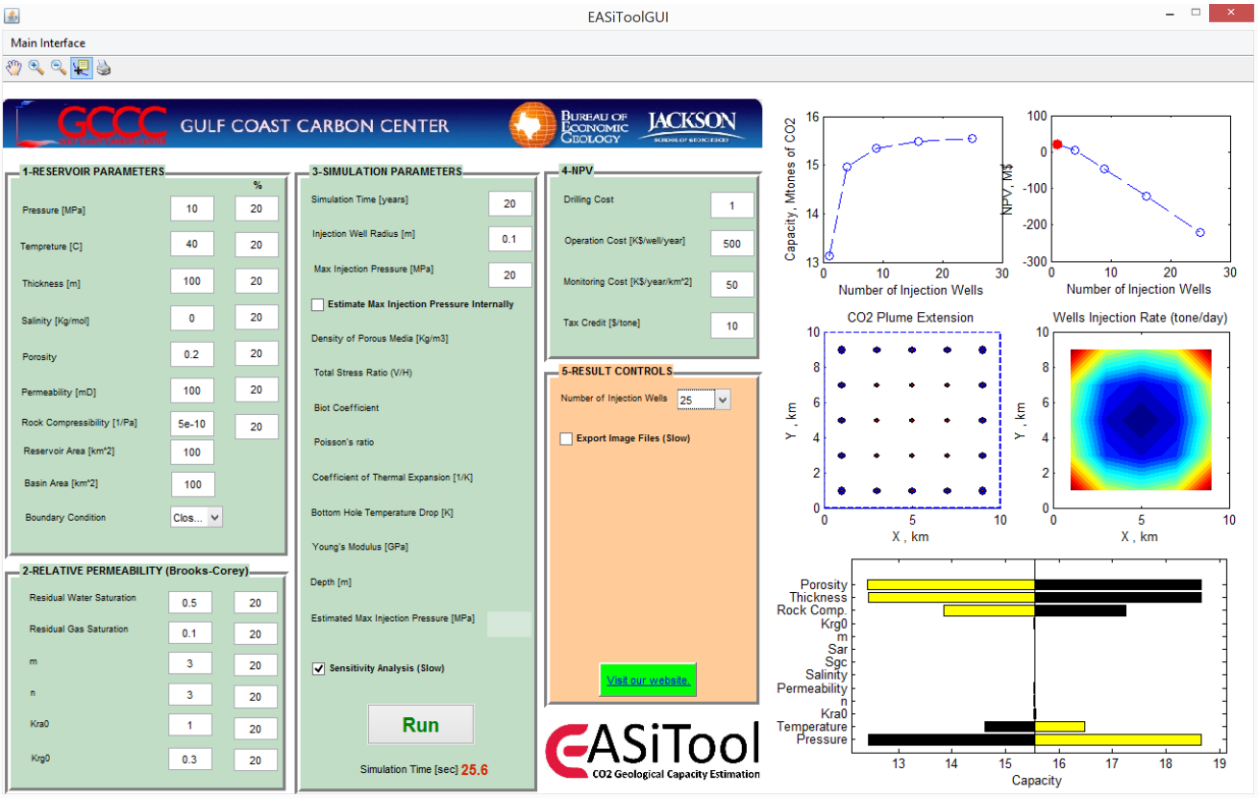
The "Zoom In" and "Zoom Out" options can be used to focus on the output figures.

To interpret the results from figures: For example, for the scenario of a total of four wells (refer to the drop-down menu in the "5-Result Controls: Number of Injection Wells" section), click on the location of all four wells on the "Well Injection Rate" plot. The pop-up boxes provide the injection rate (tonne/day) corresponding to these four wells: that is, 509.8 tonne/day for the #1 well, 509.8 tonne/day for the #2 well, 509.8 tonne/day for the #3 well, and 509.8 tonne/day for the #4 well. The rate of all four wells is similar as a result of symmetry.

Optimal constant-injection rate: This procedure guarantees that nonidentical constant-injection rates are calculated optimally at each well to meet the maximum pressure limit at the end of simulation time. For example, if the pressure limit is selected to be 20 MPa for a 20-year simulation, then the program will calculate injection rates for all wells so that the bottom-hole pressure of the wells will increase by 20 MPa at the end of 20 years.

2. Sensitivity Analysis

After completing a simulation with sensitivity analysis, you can see the results on the right-hand side of the window:



The tornado chart on the lower right-hand side shows the impact of each parameter on the total capacity. On this chart, the parameters are listed downward from the highest direct impact to the highest inverse impact.

Examples and Verifications

Table 1 summarizes the input for the EASiTool template. The aquifer is located at a depth of 1000 m. In this study, the problem was solved for closed and open boundary conditions. The basin area is the same as the reservoir area for the case of the closed boundary condition. The basin area is 10,000 km^2 for the case of the open boundary condition.

Table 1: Template Input

Initial pressure, MPa	10
Initial temperature, ˚C	40
Thickness, m	100
Salinity, kg/mol	0
Porosity	0.2
Permeability, mD	100
Rock compressibility, 1/Pa	5.0E-10
Reservoir area, km^2	100
Basin area, km^2	100 or 10000
Boundary Condition	Closed or Open

Table 2 summarizes the relative permeability parameters used in the Brooks-Corey model for a two-phase flow of gas and aqueous phases.

Table 2: Relative Permeability Parameters for Brooks-Corey Model

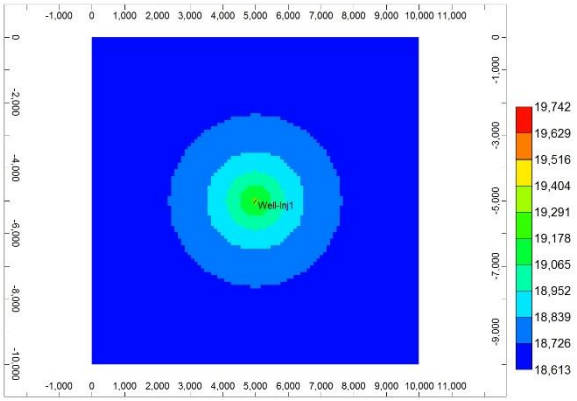
Residual water saturation, S_{wr}	0.5
Residual gas saturation, S_{gr}	0.1
Water exponent, m	3.0
Gas exponent, n	3.0
Water end-point relative permeability, k_{rw}°	1.0
Gas end-point relative permeability, k_{rg}°	0.3

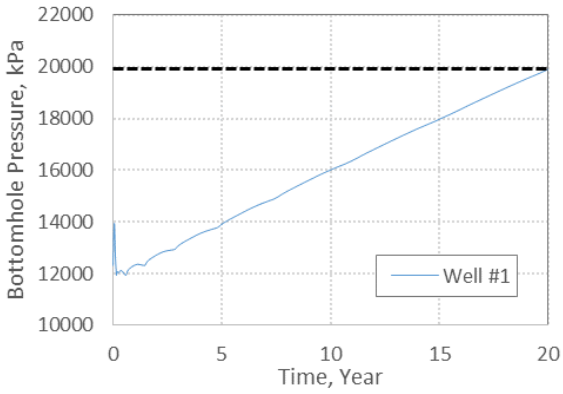
Table 3 shows the simulation parameters. It is assumed that the maximum allowable pressure in the reservoir should not be above 20 MPa after 20 years of injection with constant rates.

Table 3: Simulation Parameters

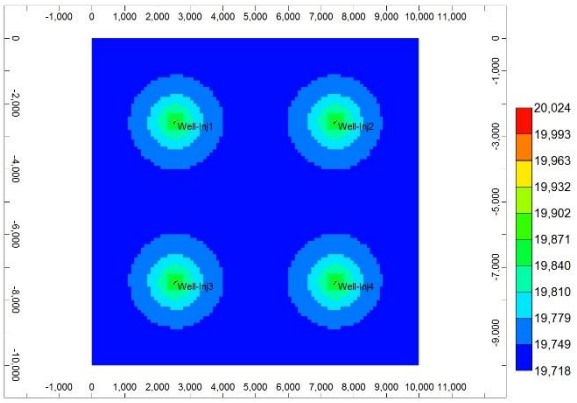
Simulation time, year	20
Injection well radius, m	0.1
Maximum injection pressure, MPa	20

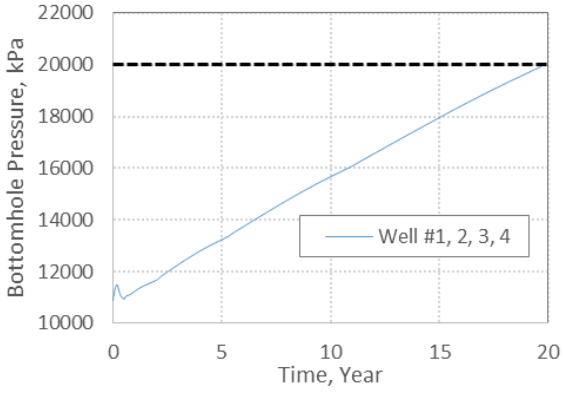
The basin models were prepared for numerical simulation using CMG-GEM for both boundary conditions. The injection rates calculated by EASiTool were used in numerical simulation to compare the analytical and numerical results. Figure 1 shows the pressure distributions throughout the reservoir and bottom-hole pressures of all wells after 20 years of injection using 1, 4, 9, and 16 injectors. The injection rates were calculated using the closed boundary condition of EASiTool. The color legend shows the range of pressure throughout the reservoir at the time of 20 years. It is observed that the maximum pressure in the reservoir is very close to the target pressure of 20 MPa. The pressure distribution is more uniform by using more injectors. The bottom-hole pressure of all wells is very similar throughout the injection period.



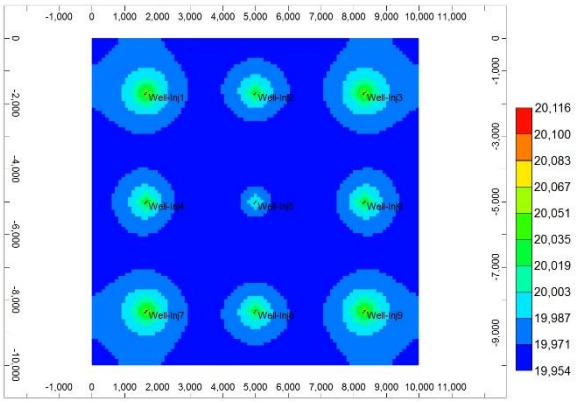


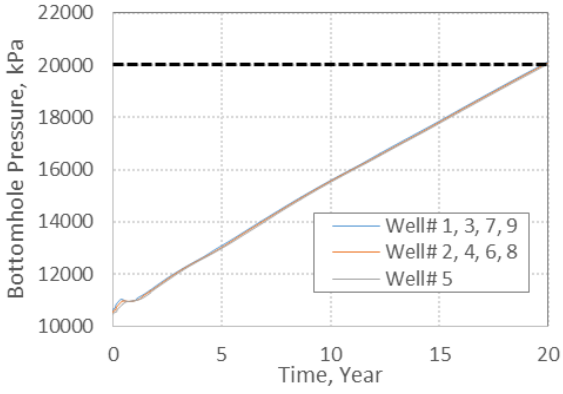
a) 1 well



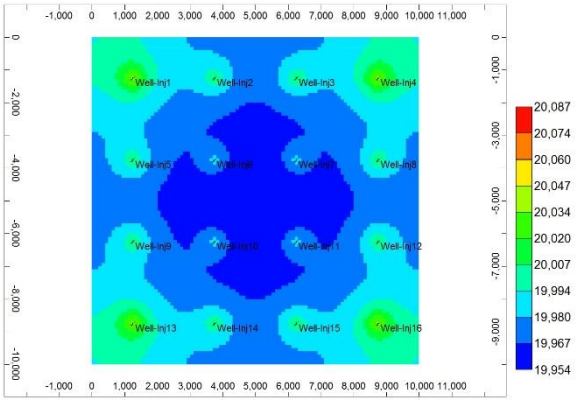


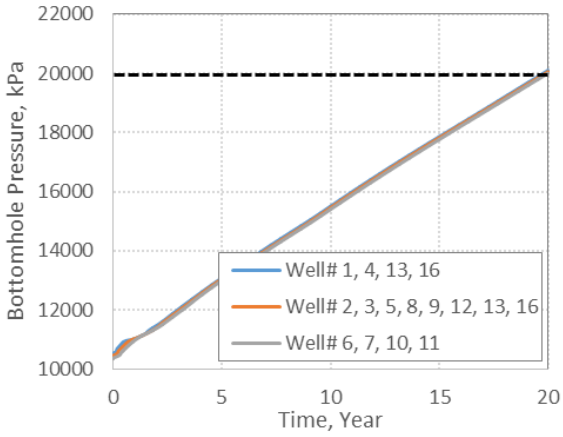
b) 4 wells





c) 9 wells

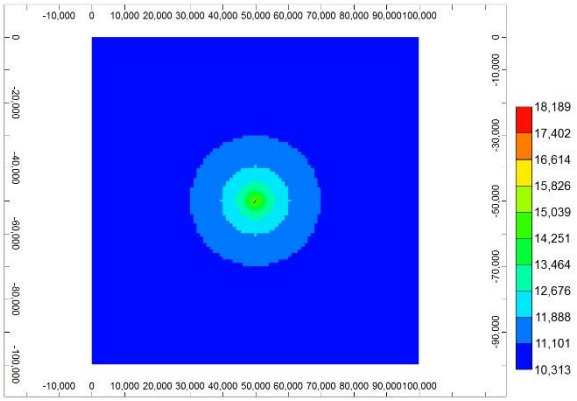


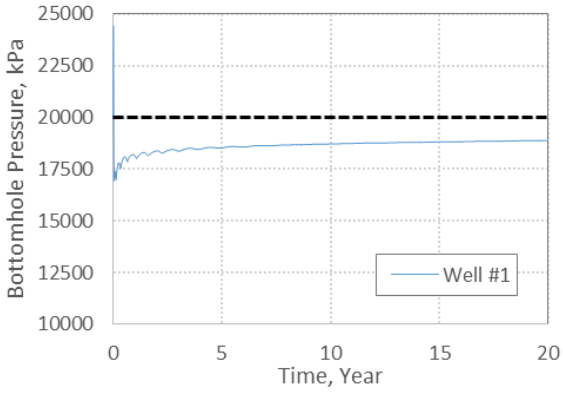


d) 16 wells

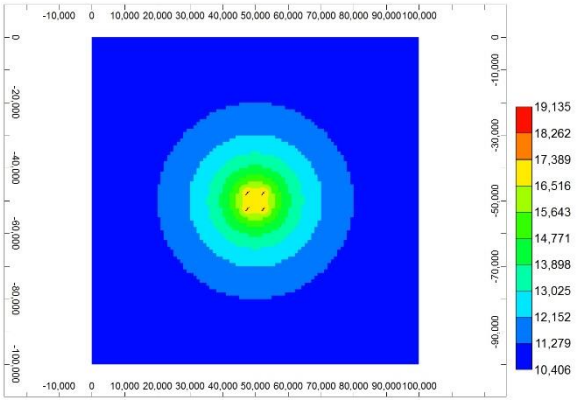
Figure 1: Pressure distributions and bottom-hole pressures for the closed boundary condition after 20 years of constant injection at depth of 1000 m.

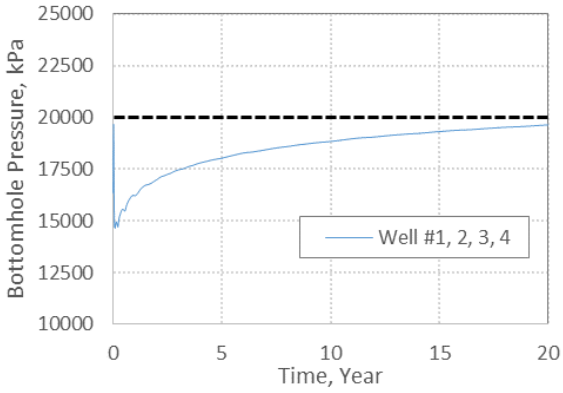
Figure 2 shows the pressure distributions and bottom-hole pressures after 20 years of injection using the open boundary condition. It is assumed that a 100 km^2 reservoir is located at the center of a 10,000 km^2 basin. There is a slight difference between the final pressure from simulations and the final pressure of 20 MPa in EASiTool. This difference decreases when more injectors are used. Also, the simulation results show that the effect of pressure reaches the boundaries of the basin at the end of injection process. It means that the open boundary condition is not accurate for a 20-year process.



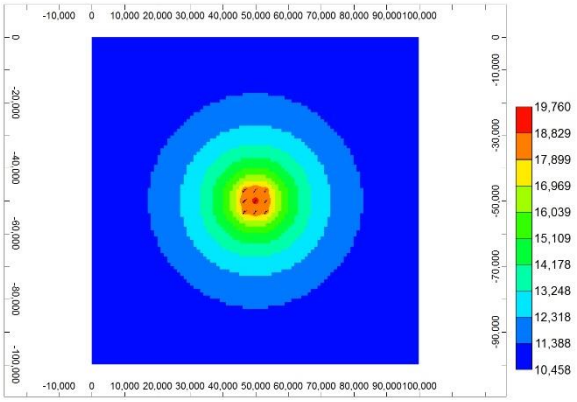


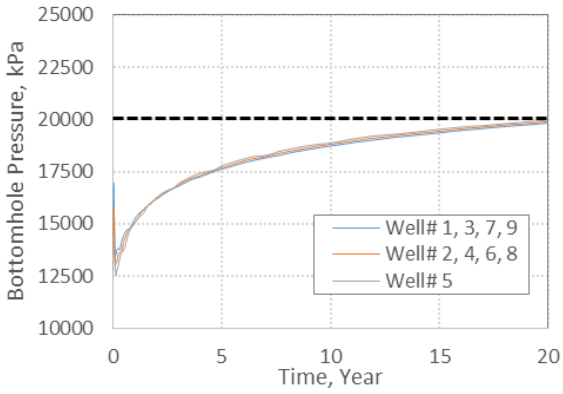
a) 1 well



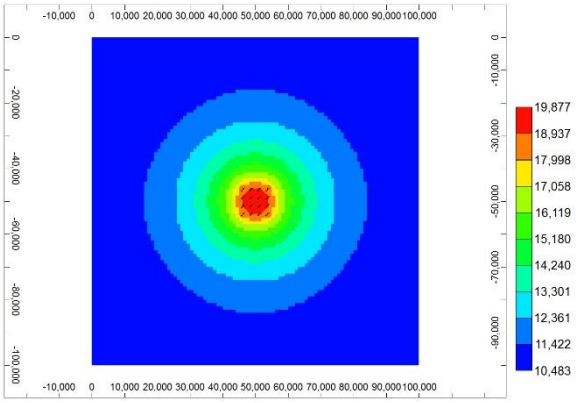


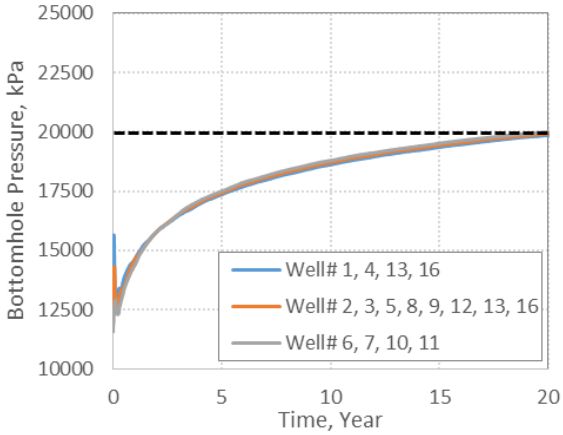
b) 4 wells





c) 9 wells





d) 16 wells

Figure 2: Pressure distributions and bottom-hole pressures for open boundary condition after 20 years of constant injection at depth of 1000 m.

Figures 3 and 4 show the maximum capacity for closed and open boundary problems versus the number of injectors. It is observed that the open boundary reservoirs have a much larger storage capacity. The storage capacity of reservoirs becomes constant after a specific number of injectors.

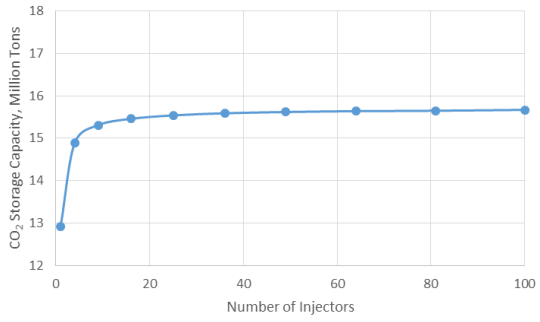


Figure 3: CO_2 capacity for 20 years of injection versus number of injectors using closed boundary condition at depth of 1000 m.

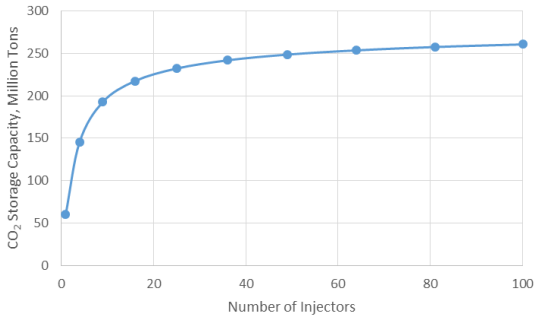
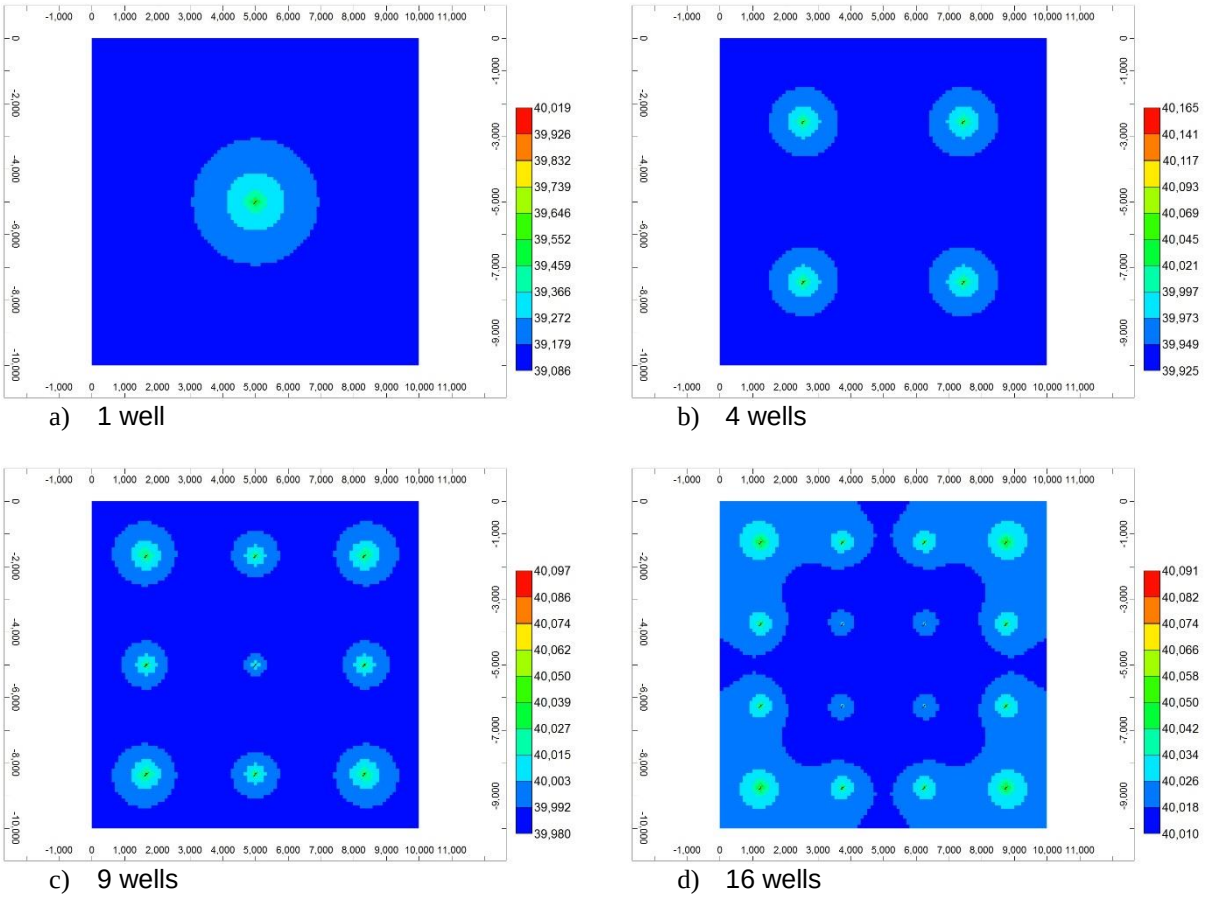


Figure 4: CO_2 capacity for 20 years of injection versus number of injectors using open boundary condition at depth of 1000 m.

The same comparative study was performed for a reservoir at a depth of 3000 m. The initial temperature and pressure in this study were 90˚C and 30 MPa, respectively. It was assumed that the maximum pressure in the reservoir would be 40 MPa after 20 years of injection. Figures 5 and 6 show the final pressure distribution obtained by simulation. Again, the results of the closed boundary case are closer to the results of EASiTool than are the results of the open boundary case.



a) 1 well b) 4 wells

c) 9 wells d) 16 wells

Figure 5: Pressure distribution for closed boundary condition after 20 years of constant injection at depth of 3000 m.

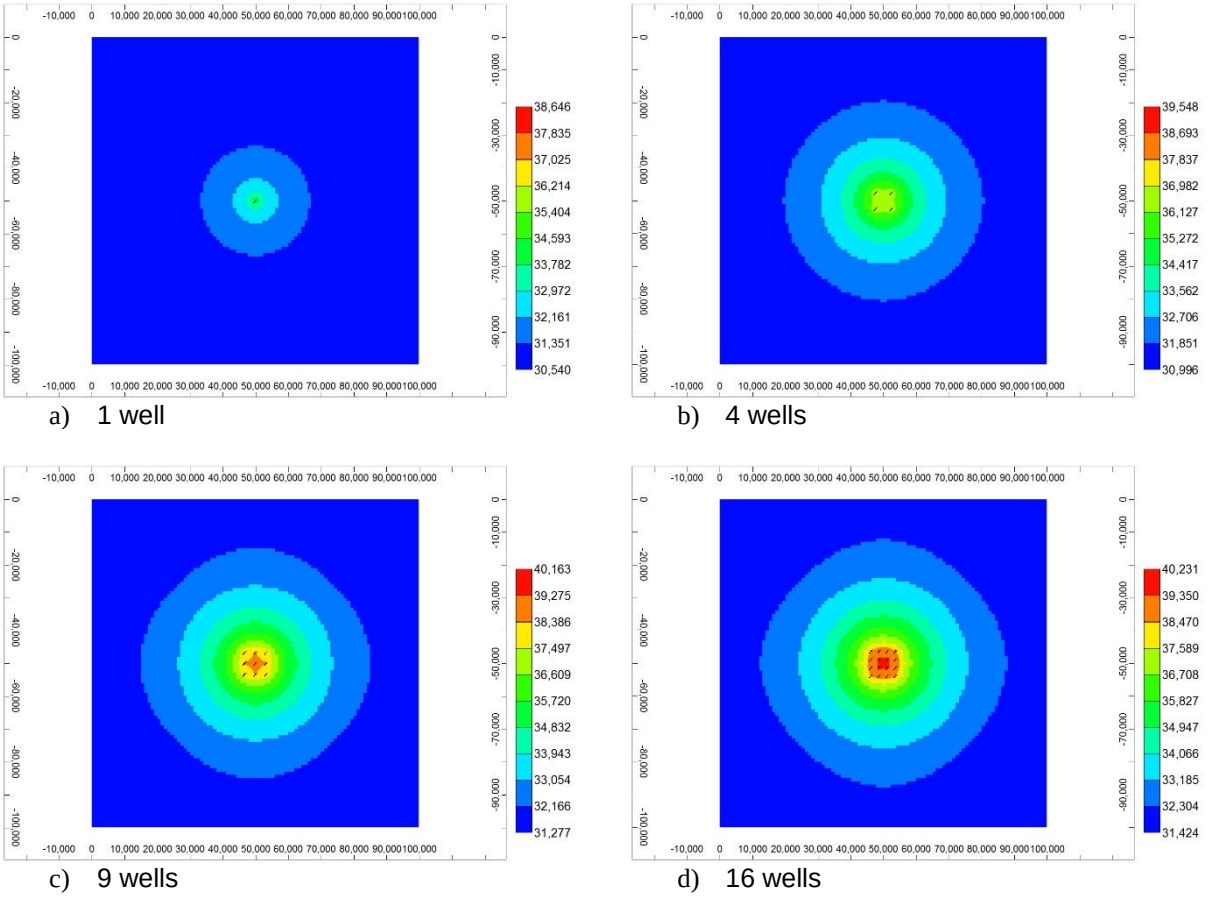


Figure 6: Pressure distribution for open boundary condition after 20 years of constant injection at depth of 3000 m.

Figures 7 and 8 show the maximum capacity for closed and open boundary problems versus the number of injectors. It is observed that the open boundary reservoirs have a much larger storage capacity.

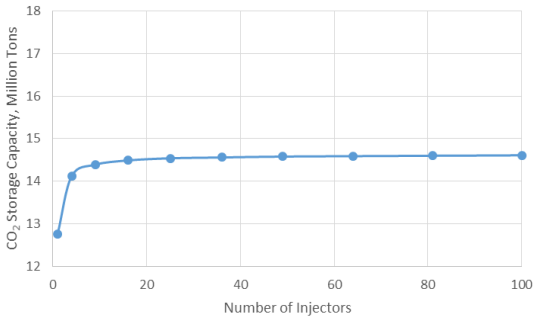


Figure 7: CO_2 capacity for 20 years of injection versus number of injectors using closed boundary condition at depth of 3000 m.

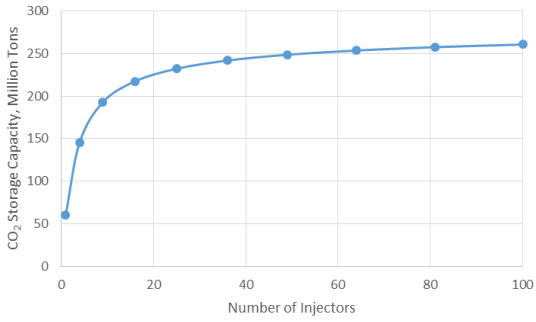


Figure 8: CO_2 capacity for 20 years of injection versus number of injectors using open boundary condition at depth of 3000 m.

EASiTool assumes that the reservoir is square, flat, and horizontal. The effect of reservoir shape and structure on the EASiTool estimations was studied. An anticline model was used for reservoir simulation with the average properties of the reservoir used as input for EASiTool. Estimated injection rates by EASiTool were also used as input for reservoir simulation. Tables 4 and 5 show the average properties of the anticline reservoir and the simulation parameters. Figure 9 shows the pressure distribution in the reservoir after 10 years of injection with 16 injectors. The simulation predicts the maximum pressure of 24.07 MPa, which is very close to the target pressure of 25 MPa.

Table 4: Properties of Anticline Reservoir

Reference pressure, MPa	16.55
Reference depth, m	1750
Initial temperature, ˚C	40
Average thickness, m	24.39
Salinity, kg/mol	0
Porosity	0.2
Permeability, mD	100
Rock compressibility, 1/Pa	5.0E-10
Reservoir area, km^2	42.87
Basin area, km^2	42.87
Boundary Condition	Closed

Table 5: Simulation Parameters

Simulation time, year	20
Injection well radius, m	0.1
Maximum injection pressure, MPa	25

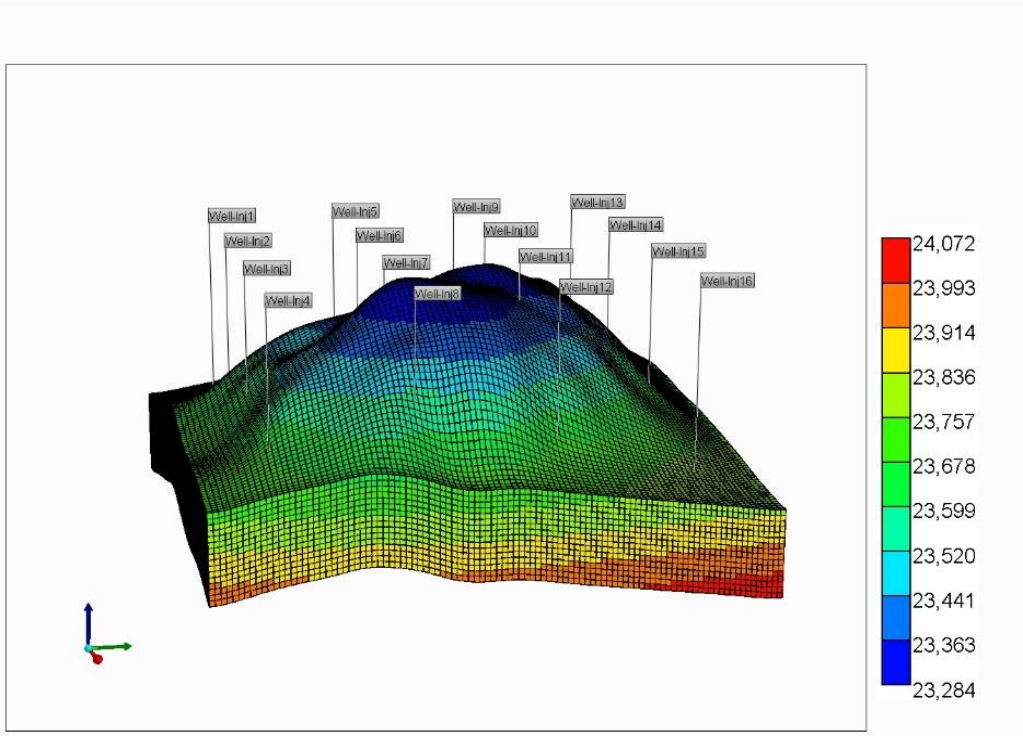


Figure 9: Pressure distribution after 20 years of injection with 16 injectors.

EASiTool assumes that the reservoir is homogeneous. The effect of reservoir heterogeneity on the EASiTool estimations was studied. The same anticline in Figure 9 was used for reservoir simulation, with the average properties and simulation parameters of Tables 4 and 5. Two realizations for permeability distribution were prepared with Petrel. Figures 10 and 11 show the histograms of the two realizations. The second model is more heterogeneous.

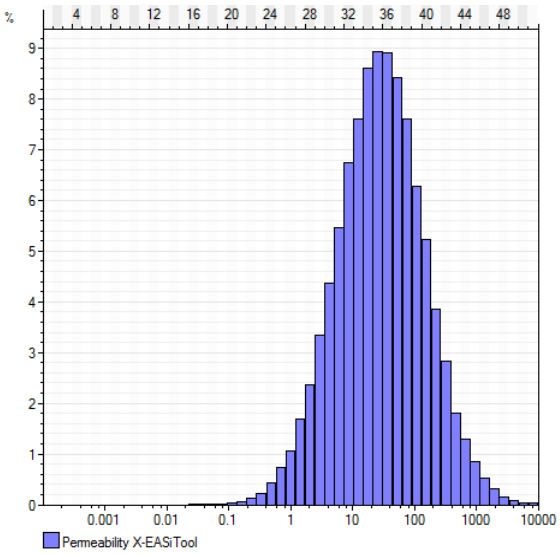


Figure 10: Histogram of permeability for first realization.

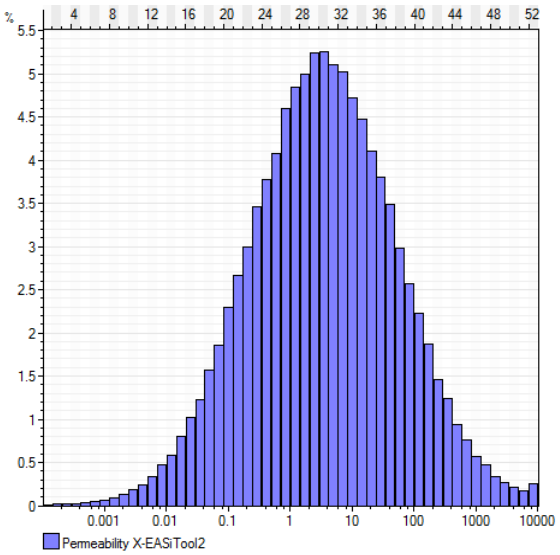


Figure 11: Histogram of permeability for second realization.

Figures 12 and 13 show the permeability distributions of the respective models. The estimated injection rates by EASiTool were used as input for reservoir simulation for both models.

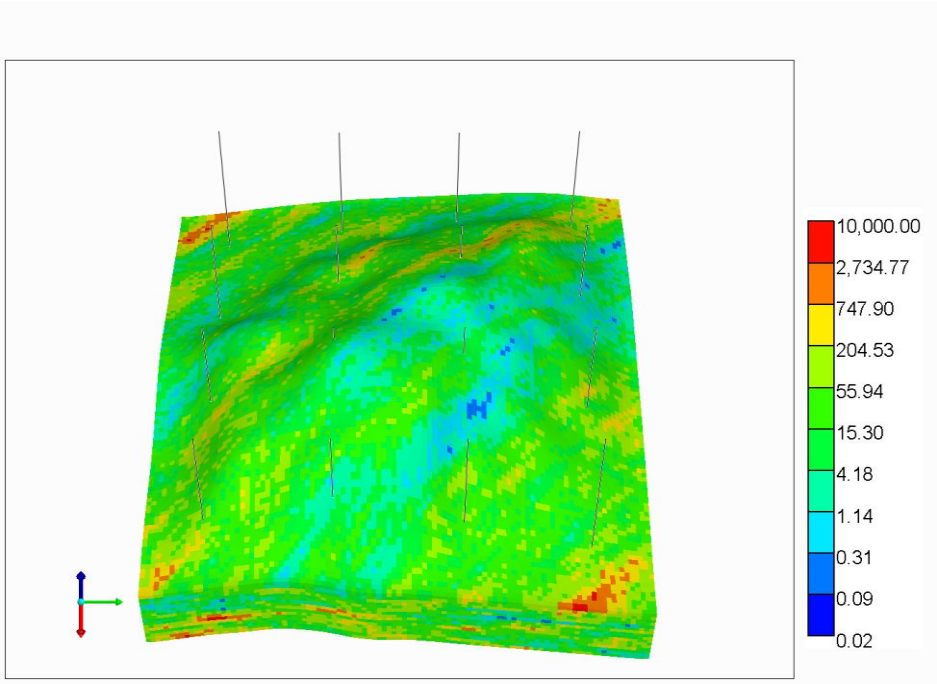


Figure 12: Permeability distribution for first realization.

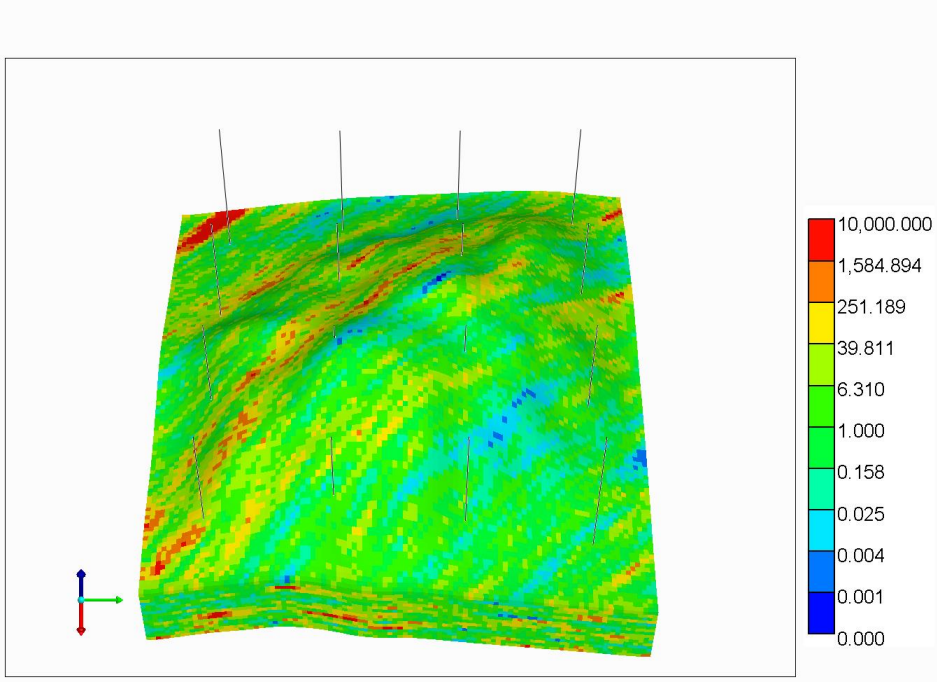


Figure 13: Permeability distribution for second realization.

Figures 14 and 15 show the pressure distribution in the reservoir after 20 years of injection with 16 injectors. The simulation predicts the maximum pressure of 25.07 and 25.51 MPa, respectively, which are very close to the target pressure of 25 MPa.

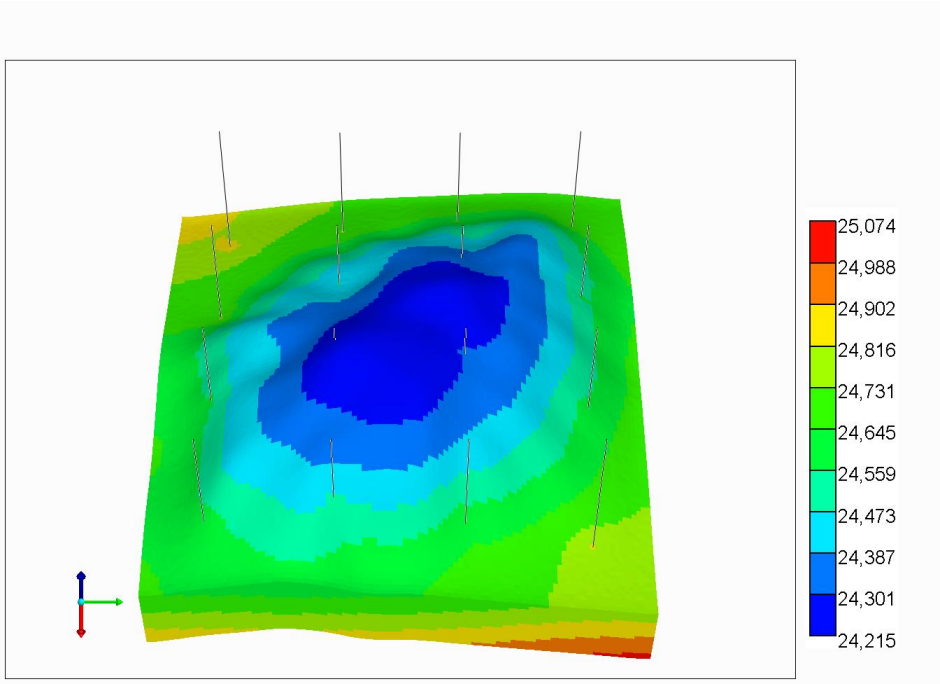


Figure 14: Pressure distribution for first realization.

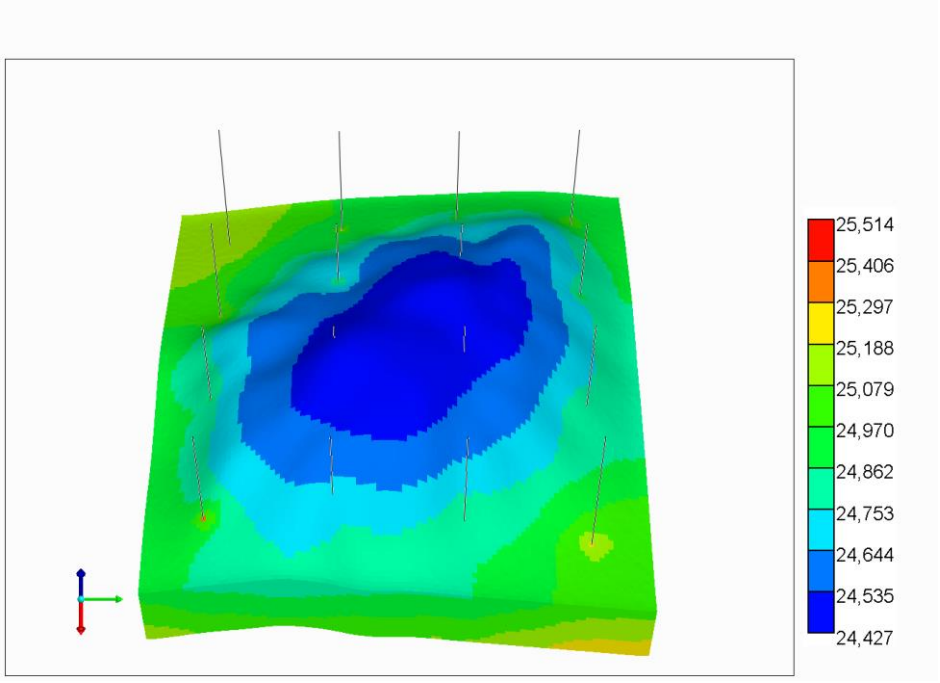


Figure 15: Pressure distribution for second realization.

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